BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-226-E - ORDER NO. 2020-832

DECEMBER 23, 2020

IN RE:	South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Dominion Energy South Carolina, Incorporated	) ORDER REJECTING DOMINION'S INTEGRATED RESOURCE PLAN AND REQUIRING DOMINION TO MAKE MODIFICATIONS TO ITS 2020 INTEGRATED RESOURCE PLAN, FUTURE UPDATES AND FUTURE INTEGRATED RESOURCE PLANS

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I. INTRODUCTION

This matter comes before the Public Service Commission of South Carolina (the "Commission") pursuant to S.C. Code Ann. § 58-37-40 (Supp. 2019) (the "IRP Statute") and Order No. 98-502 for consideration of the 2020 Integrated Resource Plan (the "IRP") of Dominion Energy South Carolina, Inc. ("DESC," "Dominion" or the "Company") as supplemented by additional material filed with the Company's rebuttal testimony (the "IRP Supplement") on August 28, 2020. This proceeding relates to the implementation by Dominion Energy South Carolina, Inc. of Integrated Resource Planning ("IRP") requirements enacted by the General Assembly in H.3659, also known as the South Carolina Energy Freedom Act ("Act 62"). DESC filed its IRP on February 28, 2020 as required by the IRP Statute, which was one (1) year from the filing of its most recent IRP Update and three (3) years from the filing by DESC of its last full IRP in 2017.

In 2019, the General Assembly extensively amended the IRP Statute in Act No. 62.[1] Since 1992, the IRP Statute was nothing more than a "filing only" statute that did not allow the Commission to conduct any review or to take action related to a utility's IRP. Now, the Commission is authorized to review the utility's IRP in a contested case proceeding with the mandatory participation by the Office of Regulatory Staff ("ORS") and the right for any interested

[1] Section 58-37-10(2) of the South Carolina Code of Law defines an integrated resource plan to mean "a plan which contains the demand and energy forecast for at least a fifteen-year period, contains the supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options, with a brief description and summary cost-benefit analysis, if available, of each option which was considered, including those not selected, sets forth the supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and describes the external environmental and economic consequences of the plan to the extent practicable. For electrical utilities subject to the jurisdiction of the South Carolina Public Service Commission, this definition must be interpreted in a manner consistent with the integrated resource planning process adopted by the commission. For electric cooperatives subject to the regulations of the Rural Electrification Administration, this definition must be interpreted in a manner consistent with any integrated resource planning process prescribed by Rural Electrification Administration regulations." S.C. Code Ann. § 58-37-10(2) (2015).

persons to intervene. S.C. Code Ann. § 58-37-40(C)(1) (Supp. 2019).

The General Assembly expresses its purpose and policies through the statutes it enacts and, as such, a statute must be given a reasonable and practical construction consistent with the purpose and policy expressed in the statute. *Davis v. NationsCredit Fin. Servs. Corp.*, 326 S.C. 83, 484 S.E.2d 471 (1997); *Georgia-Carolina Bail Bonds, Inc. v. Cty. of Aiken*, 354 S.C. 18, 22–23, 579 S.E.2d 334, 336 (Ct. App. 2003); *Daisy Outdoor Adver. Co. v. South Carolina Dep't of Transp.*, 352 S.C. 113, 120, 572 S.E.2d 462, 466 (Ct.App.2002); *Stephen v. Avins Constr. Co.*, 324 S.C. 334, 478 S.E.2d 74 (Ct.App.1996). It is clear that the General Assembly wants the process, development, and now review of a utility's IRP to be substantive, meaningful and of value for the public's interest.

South Carolina Code Section 58-37-40, as amended, provides a detailed list of required elements and analyses to be included in the utility's IRP. The commission shall approve an electrical utility's IRP "***if*** the Commission determines that the proposed integrated resource plan represents the ***most reasonable and prudent means*** of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed" by the Commission. S.C. Code Ann. § 58-37-40(C)(2) (Supp. 2019) (emphasis added). To determine whether the Company's IRP is the most reasonable and prudent means of meeting energy and capacity needs, the Commission is directed to consider, in its discretion, whether the plan appropriately balances the following factors : (a) resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins; (b) consumer affordability and least cost; (c) compliance with applicable state and federal environmental regulations; (d) power supply reliability; (e) commodity price risks; (f) diversity of generation supply; and (g) other foreseeable conditions that the commission determines to be for the public interest. *Id.* DESC is the first IRP proceeding conducted under the amended statute. As part of its review, the Commission also provides guidance on its interpretation and expectations for compliance with the statute for the public interest not only for DESC, but also for other electrical utilities.

Pursuant to S.C. Code Ann. § 58-37-40 C (2), the Commission rejects the Proposed 2020 IRP as filed by DESC and requires the utility to modify and refile a Modified 2020 IRP as detailed in this Order within sixty (60) days from the final Order. S.C. Code Section 58-37-40(C)(3) (Supp. 2019). As further explained herein, the Commission does not believe that DESC's IRP represented the most reasonable and prudent means for DESC to meet its energy and capacity needs. The Commission further believes that its detailed analysis and plan review set forth in this Order is consistent with the intent and purpose of the General Assembly which extensively amended the IRP Statute. The Commission recognizes that this proceeding is the first utility IRP examined under the amended IRP Statute. The work of DESC is appreciated, as well as the efforts by DESC, ORS, and intervening parties to address additional scenarios, adjust assumptions, correct certain transcription and formula errors, revise analyses, and additional modeling as a result of the information exchanged between the parties that have formulated the testimony, exhibits, and record of this proceeding.

In brief, we find significant deficiencies in the *2020 Integrated Resource Plan of Dominion Energy South Carolina, Inc.* ("Proposed IRP") filed by DESC with this Commission on February 28, 2020 - and supplemented on August 28, 2020 - and reject the Proposed IRP. The DESC IRP is rejected and must be modified to meet more detailed best management practices as presented in the hearing and be the best possible and practical IRP from which to base and model integrated resource planning and ratepayer risk. The Commission will require DESC to make a number of changes to its candidate resource plans, modeling assumptions, and methodologies, and to file a Modified IRP within sixty (60) days reflecting those changes. The Commission also requires a number of more complex changes to its methods for preparing an IRP, which DESC will be required to implement in a full IRP in 2023. Requiring these additional changes to be implemented in the 2023 IRP will allow these changes to be implemented in a reasonably timely fashion and also will enable Commission and intervenor review of those changes, which is appropriate given the fundamental importance and also the complexity of integrated resource planning.

A. Background on Integrated Resource Planning

Integrated Resource Planning is a structured, transparent process for comparing options to meet electric demand. It was introduced in the electric sector in the 1980s, has been widely adopted across the US, and continues to play a key role todayin most states. IRP serves a unique and vital purpose within utility regulation; in that it provides a way to comprehensively and systematically consider the wide array of factors that impact electric system choices. When implemented prudently, IRP can save ratepayers billions of dollars, help regulators understand risk exposure and make decisions that align with their risk preferences, improve environmental outcomes, and facilitate stakeholder buy-in for utility plans. It is a powerful tool but must be implemented carefully to provide these benefits.[2] The Legislature, in passing Act 62, significantly strengthened the IRP process in South Carolina. Compared to the previous IRP statute, Act 62 includes an expanded and more detailed list of requirements for utility IRP filings. Act 62 also enabled formal Commission review of utility plans via a litigated proceeding, in which the Commission must ultimately accept, reject, or order modifications to the utility's

[2] Tr. p. 607.4, ll. 13-14.

proposal. These statutory changes signal both the heightened importance the South Carolina General Assembly has assigned to IRP and also the critical role assigned to this Commission in reviewing and ruling on proposed utility plans. As commonly implemented, the IRP process involves five basic steps: (1) forecast future electricity demand; (2) identify the goals and regulatory requirements the process must meet; (3) develop a set of resource portfolios designed to achieve those goals; (4) evaluate those resource portfolios; and (5) identify a preferred resource plan.[3]

B. Notice and Intervention

By letter of March 26, 2020, the Clerk's Office of the Public Service Commission of South Carolina transmitted the Notice of Filing and Hearing and Prefile Testimony Deadlines ("Notice") in the above-referenced docket to DESC and instructed DESC to publish the Notice in newspapers of general circulation in the affected areas by May 7, 2020, and provide proof of publication on or before June 4, 2020. The Notice indicated the nature of the proceeding and advised all parties desiring participation in the scheduled proceeding of the manner and time in which to file appropriate pleadings. On May 14, 2020, the Company filed an affidavit demonstrating that the Notice was duly published in accordance with the instructions set forth in the March 26, 2020 letter.

Petitions to Intervene were received from the South Carolina Solar Business Alliance ("SCSBA"), South Carolina Coastal Conservation League ("CCL") and the Southern Alliance for Clean Energy ("SACE"), the Sierra Club, and Johnson Development Associates, Incorporated ("JDA"). The South Carolina Department of Consumer Affairs ("SCDCA") was

[3] *Id.* at Tr. pp. 607.6, l.12 - 607.8, l. 2.

notified of this proceeding pursuant to S.C. Code Ann. § 37-6-604(C) and submitted a petition to intervene. The Petitions to Intervene of SCSBA, CCL, SACE, Sierra Club, JDA, and SCDCA were not opposed by DESC, and no other parties sought to intervene in this proceeding. The South Carolina Office of Regulatory Staff ("ORS") is automatically a party to this docket by virtue of S.C. Code Ann. § 58-4-10(B) (2015).

II. **REQUIREMENTS FOR INTEGRATED RESOURCE PLANNING UNDER ACT 62**

As codified in S.C. Code Ann. § 58-37-40, the statutes set forth procedural and substantive requirements for utility IRP filings along with the standard of review for the Commission's review of utility IRPs.

A. **Procedural Requirements**

Regulated electric utilities in South Carolina must prepare and submit IRPs with the Commission at least every three years. S.C. Code Ann. § 58-37-40(A). The Commission is required to establish a proceeding to review each utility's IRP in which interested parties may intervene and conduct discovery for the purpose of "obtaining evidence concerning the [IRP], including the reasonableness and prudence of the plan and alternatives to the plan raised by intervening parties." S.C. Code Ann. § 58-37-40 (C)(1).

Within 300 days of the IRP being filed, the Commission must issue a final order approving, modifying, or denying the plan. *Id.* If the Commission modifies or rejects a utility's IRP, the utility has 60 days from the date of the final order to submit a revised plan to the Commission. S.C. Code Ann. § 58-37-40(C)(3). Within 60 days after the utility makes its revised filing, ORS must review the electrical utility's revised plan and submit a report to the Commission assessing the sufficiency of the revised filing; other parties to the IRP proceeding also may submit comments. *Id.* Within 60 days after the ORS report is filed, the Commission at its discretion may determine whether to accept the revised IRP or to mandate further remedies as it deems appropriate. *Id.*

Act 62 also establishes that utilities must file annual IRP updates before the Commission. S.C. Code Ann. § 58-37-40(D).

B. Required Elements of Utility IRPs

S.C. Code Ann. § 58-37-40(B)(1) states that utility IRPs *must* include the following elements:

> (a) A long-term forecast of the utility's sales and peak demand under various reasonable scenarios;
> (b) The type of generation technology proposed for any generation facility contained in the plan and its proposed capacity, including fuel cost sensitivities under various reasonable scenarios;
> (c) Projected energy purchased or produced by the utility from a renewable energy resource;
> (d) A summary of electrical transmission investments planned by the utility;
> (e) Several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency (EE), and demand response (DR) measures, including consideration of:
> i. customer energy efficiency and demand response programs;
> ii. facility retirement assumptions; and
> iii. sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;
> (f) Data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;
> (g) Plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;
> (h) An analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and
> (i) A forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.

S.C. Code Ann. § 58-37-40(B)(1)(Supp.2019).

In addition, S.C. Code Ann. § 58-37-40(B)(2)(Supp. 2019) states that IRPs may include distribution resource plans or integrated system operation plans.

C. Standard of Review

The Commission is directed to approve a utility's IRP if it finds that "the proposed integrated resource plan represents the *most reasonable and prudent* means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed." S.C. Code Ann. § 58-37-40(C)(2)(Supp. 2019) (emphasis added).

> To determine whether this standard was met, the Commission is directed to consider, in its discretion, whether the IRP appropriately balances the following seven factors:
> (a) Resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins;
> (b) Consumer affordability and least cost;
> (c) Compliance with applicable state and federal environmental regulations;
> (d) Power supply reliability;
> (e) Commodity price risks;
> (f) Diversity of generation supply; and
> (g) Other foreseeable conditions the Commission determines to be for the public interest.

Id.

Given the importance of this standard to its findings below, the Commission finds it necessary to further expound on this standard and the factors relevant to whether or not it is satisfied. As an initial matter, the plan must be "reasonable," meaning it is rational, logically consistent, and the result of sound judgment. In the context here, this requires consideration of whether the utility's plan meets the requirements of Act 62 and comports with industry norms and widely-known IRP best practices. (Tr. pp. 476.7, l. 25 – 476.8, l. 6.) The plan must also be "prudent," which implies that it gives due consideration to actual and foreseeable future conditions and risks. Such consideration should take into account the relative costs and benefits of avoiding potential future risks, such as regulatory, capital, or fuel risks. The Commission emphasizes that although cost is an important consideration, "reasonableness" and "prudence" do not require that the utility simply select the least-cost resource plan given the inherent uncertainty of sensitivity assumptions for future conditions. For example, if two plans have nearly the same expected cost, it may be more reasonable and prudent to select the more expensive of the two, if consideration of the other statutory factors (e.g. commodity price risk or diversity of generation) strongly favors that plan.

The Commission's decision must be based on the facts in the record before it; this means that the IRP and the record must provide sufficient information about each of the seven balancing factors to enable the Commission to determine if the IRP appropriately balances each of them. Act 62 also requires that the plan must represent the *most* reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed. This is a significant standard that implies that IRP requirements should not be static, but rather should continuously improve over time as standards and practices improve and evolve. It also implies that a utility may not do the bare minimum, but rather must ensure that its IRP is the result of serious planning and consideration using the best available data and tools available to it.

Consistent with the purposes of Act 62 and other sections of the Act,[4] the Integrated Resource Planning provisions of Act 62 include requirements intended to identify and mitigate potential risks to ratepayers. IRPs must include multiple resource portfolios evaluated under

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[4] Cf. S.C. Code Ann. § 58-41-20(A) (Supp. 2019).

"sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks." S.C. Code Ann. § 58-37-40(B)(1)(e)(iii). For these various sensitivity analyses, the Act also specifies the required use of "reasonable scenarios." S.C. Code Ann. 58-37-40(B)(1)(b).

When determining whether an integrated resource plan is the most reasonable and prudent means of meeting a utility's energy and capacity needs, Act 62 requires that the Commission balance a number of factors, including "commodity price risks" and "diversity of generation supply" S.C. Code Ann. 58-37-40(C)(2)(e) and (f).

III. HEARING

In order to consider the merits of this case, the Commission convened a hearing on this matter on October 12-14, 2020, with the Honorable Justin T. Williams presiding. DESC was represented by K. Chad Burgess, Esquire; Matthew W. Gissendanner, Esquire; Belton T. Zeigler, Esquire; and Katheryn S. Mansfield, Esquire. CCL and SACE were represented by Katherine "Kate" N. Lee, Esquire; Gudrun E. Thompson, Esquire; and Frank S. Holleman, III, Esquire. SCSBA was represented by Benjamin L. Snowden, Esquire and Richard L. Whitt, Esquire. Sierra Club was represented by Dorothy E. Jaffe, Esquire and Robert Guild, Esquire. JDA was represented by Weston Adams, III, Esquire and Courtney E. Walsh, Esquire. Nanette S. Edwards, Esquire; Jeffrey M. Nelson, Esquire; and Andrew M. Bateman, Esquire, represented ORS. In this Order, ORS, CCL, SACE, SCSBA, Sierra Club, JDA and DESC are collectively referred to as the "Parties" or sometimes individually as a "Party."

DESC presented the direct testimonies and exhibits of Eric H. Bell, Therese A. Griffin, James W. Neely, P.E., and Joseph M. Lynch. ORS presented the direct testimonies and exhibits of Anthony M. Sandonato, Philip Hayet, Stephen J. Baron, and Lane Kollen. CCL and SACE presented the direct testimony and exhibits of David G. Hill, Ph.D and Anna Sommer. SCSBA presented the direct testimony and exhibits of Kenneth Sercy. Sierra Club presented the testimony and exhibits of Derek P. Stenclik. JDA did not present witnesses at the hearing.

In response to the direct testimony filed by CCL and SACE, SCSBA, Sierra Club and ORS, DESC presented the rebuttal testimony and exhibits of Eric H. Bell, Therese A. Griffin, James W. Neely, P.E., and Joseph M. Lynch. In response to DESC's rebuttal testimony, CCL and SACE filed surrebuttal testimony of Witnesses Hill and Sommer; SCSBA filed surrebuttal testimony of Witness Sercy; Sierra Club filed surrebuttal testimony of Witness Stenclik; and ORS filed surrebuttal testimony of Witnesses Sandonato, Hayet, Baron, and Kollen. The Commission also requested and received late-filed exhibits from several parties.

IV. FINDINGS OF FACT

Based on the Proposed IRP, the testimony, and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission hereby makes the following findings of fact:

Implementation of Changes to DESC IRP Practices

1. It is reasonable to require DESC to implement certain changes to its IRP in a Modified 2020 IRP filed within sixty (60) days of the final Order, as provided for in Act 62 and as more fully described below. The Modified 2020 IRP shall be a complete, stand-alone document. Other changes will require more time to implement, but given their nature and complexity, these changes should be subjected to input by other stakeholders and scrutiny by the Commission. Therefore, it is reasonable to require DESC to file an IRP Update in 2021 and 2022, as required by Act 62, and a complete IRP in 2023, as authorized by the Act. All changes to DESC's IRP development methodologies required to be included in the Modified 2020 IRP should be reflected in the 2021 IRP Update.

2. It is reasonable to initiate an ongoing IRP Stakeholder Process for the purpose of considering, and inviting stakeholder input and review on, certain potentially complex changes to DESC's IRP development methodology, modeling inputs and assumptions. It is reasonable to require that the stakeholder process should begin by the time of the filing of Dominion's Modified 2020 IRP. It is reasonable that, at the time of the filing of Dominion's Modified IRP, Dominion shall be able indicate to the Commission the composition of current and prospective stakeholders, and report on any stakeholder meetings that have occurred prior to the filing date. For a stakeholder process to be most beneficial to the IRP process, stakeholders to the IRP actions should be comprised of representatives from multiple interest groups, to include residential and industrial classes of ratepayers and the Office of Regulatory Staff.

Candidate Resource Plans

3. In selecting candidate resource plans in the IRP, DESC did not use capacity expansion modeling software, which is widely used in the electric utility industry and represents industry best practice. It is reasonable to require DESC to adopt and implement the use of capacity expansion software starting in the 2022 IRP Update, while requiring input from on the selection and implementation of the software, and ensuring that the software meets the transparency requirements of Act 62.

4. In selecting candidate resource plans, DESC failed to consider major categories of potential candidate resource plans, including near-term clean energy deployment and coal retirement. Consequently, the Proposed IRP does not include resource portfolios that fairly evaluate the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. It is reasonable to require DESC to model a

limited set of additional resource plans as specified by SCSBA and to include them in a Modified 2020 IRP filed in this docket within 60 days of the Order.

5. It is reasonable for the Commission to require DESC to perform a comprehensive coal retirement analysis to inform development of its 2022 IRP Update and its 2023 IRP and to solicit parties' recommendations on guidelines for performing this analysis through the ongoing IRP Stakeholder Process. Upon completion of the coal retirement study – and targeting the 2023 IRP - DESC shall begin modeling coal retirement as an option in the various scenarios.

6. It was unreasonable for DESC not to include DSM and purchased power as resource options to be incorporated in candidate resource plans and evaluated across multiple scenarios. It is reasonable to require DESC, in its 2022 IRP Update, to include additional candidate resource plans including DSM and purchased power as resource options that are incorporated into candidate resource plans and evaluated across multiple scenarios.

7. It was unreasonable for DESC to design its candidate resource plans to meet only its base reserve margin rather than its full peaking reserve margin. It is reasonable to require DESC, in its Modified 2020 IRP, to build candidate resource plans to meet its full peaking reserve margin target, and the resource plan analysis should determine what type of resources best meet the peaking increment.

Modeling of Candidate Resource Plans

8. In modeling the costs of its candidate resource plans, DESC used a number of assumptions requiring improvement. These include: (a) invalid solar photovoltaic ("PV") cost and system value assumptions, (b) inappropriate battery storage assumptions, although the Supplemental IRP filed by DESC incorporates reasonable battery storage cost assumptions; (c) incorrect Internal Combustion Turbine (ICT) capital cost assumptions based on a volumetric

discount; and (d) incorrect implementation of the battery and solar capital cost escalation rates in its Supplemental 2020 IRP. It is reasonable to require DESC to re-run its IRP modeling using the set of assumptions recommended in SCSBA Witness Sercy's Rebuttal Testimony and Sierra Club Witness Derek Stenclik's Rebuttal Testimony, and to include the results of that modeling in its Modified 2020 IRP.

9. It is appropriate to require Dominion to work with stakeholders regarding fair inclusion of solar PV's winter capacity value in the 2021 and 2022 IRP Updates. It is unreasonable for DESC to utilize modeling assumptions related to solar or renewable integration costs that are inconsistent with prior orders of this Commission or using methodologies that have not been approved by the Commission. Until a reliable metric for solar and renewable integration costs can be established through the Interconnection Study called for by Act 62, it is reasonable to require DESC, in its production cost modeling, to assume integration costs for solar at the interim rate set by the Commission in Docket No. 2019-184-E.

Scenario Analysis and Selection of Preferred Plan

10. DESC did not properly assess risk and uncertainty, as required by Act 62, when analyzing and selecting a preferred resource plan. The Proposed IRP does not adequately protect South Carolina ratepayers from a range of foreseeable risks, because it models an unreasonably limited selection of resource plans, and selects a preferred resource plan based on the fact that it is least cost under only a limited set of possible scenarios.

11. Comparing risk metric values for candidate resource plans is an appropriate means for considering Act 62 factors such as commodity price risk and diversity of generation supply. Cost range and minimax regret analyses are simple, appropriate methodologies that can feasibly be implemented in a Modified 2020 IRP. It is reasonable to require DESC to submit a

Modified 2020 IRP including a comparison of candidate resource plans employing simple quantitative risk metrics, including cost ranges and regret scores, as recommended by SCSBA Witness Sercy in his direct and rebuttal testimony. DESC should also consider, with stakeholder input, implementation of more sophisticated risk-adjusted metrics in the 2022 IRP Update.

12. DESC's scenario analysis does not consider a sufficiently wide range of possible load conditions, gas prices, or CO2 prices. It is reasonable to require DESC to conduct a revised scenario analysis based on modeling that reflects a wider range of possibilities, as proposed by SCSBA. It is also reasonable to require DESC to include the results of this analysis in a Modified 2020 IRP filed in this docket.

13. The Commission finds that DESC's Proposed IRP does not include an evaluation of a high case for the adoption of energy efficiency ("EE") and demand response measures as required by S.C. Code Ann. § 58-37-40(B)(1)(e). DESC's 2019 Market Potential Study did not evaluate the cost effectiveness or achievability of the high DSM case, and it was unreasonable for DESC to rely on that study in dismissing the high DSM case—which was least cost under nearly all portfolios and scenarios DESC evaluated—as "not cost effective and likely not achievable." Accordingly, the Commission finds it reasonable to require that DESC work with the DSM Advisory Group ("Advisory Group") to conduct a rapid assessment of the cost-effectiveness and achievability of ramping up its current DSM portfolio, such as by expanding programs or increasing spending, to achieve at least a 1% level of savings in the years 2022, 2023, and 2024, and to require that DESC include this analysis in its Modified 2020 IRP. It is also reasonable to require DESC to include in the Modified 2020 IRP action steps it will take to complete the comprehensive DSM evaluation described in Finding 17 below.

14. It is reasonable to require that DESC include in its 2023 IRP a comprehensive

evaluation of the cost-effectiveness and achievability of DSM portfolios reaching 1% and higher savings, including savings levels of 1.25%, 1.5%, 1.75% and 2%, and to work with the Advisory Group to develop and characterize these levels of DSM savings.

15. It is reasonable to require that DESC include in its Modified 2020 IRP a DSM Action Plan that includes its plans to undertake a comprehensive evaluation of the cost-effectiveness and achievability of DSM portfolios reaching 1% and higher savings, including savings levels of 1.25%, 1.5%, 1.75% and 2%, and to work with the Advisory Group to develop and characterize these levels of DSM savings. Further, it is reasonable to require that DESC include this comprehensive evaluation in its 2023 IRP.

16. The Proposed IRP does not appropriately balance the factors set forth in S.C. Code Ann. § 58-37-40(C)(2)(a)-(g), in particular commodity price risk, diversity of generation supply, and other foreseeable conditions that the Commission determines to be for the public interest. It is in the public interest for the risk of potential carbon pricing to also be considered and balanced under Section 58-37-40(C)(2)(g).

17. It is reasonable to require DESC, starting in the 2022 IRP Update, to specifically consider and discuss diversity of its generation supply, and to (a) propose candidate resource plans designed to further diversify its generation supply and (b) include diversity of generation supply in the weighting of candidate resource plans.

18. DESC failed to demonstrate that its preferred resource plan ("Resource Plan 2" or "RP2") represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs at this time.

19. DESC did not provide adequate information in its IRP regarding the impact of its Proposed IRP on customer affordability. It is reasonable to require that DESC provide

information regarding the proposed bill impacts to customers from each of its modeled resource portfolios.

20. The Proposed IRP does not provide adequate information regarding compliance with applicable state and federal regulations. It is reasonable to require that DESC revise its IRP to include further information regarding current, expected, and reasonably foreseeable future regulations, including potential greenhouse gas regulations, and associated potential impacts on DESC's resource planning.

21. The Proposed IRP does not provide sufficient information for the Commission to evaluate the plan in light of "power supply reliability." It is reasonable to require that DESC include recent generator performance and other reliability data in its Modified 2020 IRP and future IRPs. It is also reasonable to require DESC to include in its Modified 2020 IRP additional information regarding storm and hurricane-related outages and their impact on resource planning.

Competitive Procurement of Renewable Resources

22. Even in the absence of a need for additional capacity, procurement of energy from solar and/or storage resources in the near term may result in savings for ratepayers, if those resources can provide energy to the system more economically than existing generation resources or alternatives contemplated in the IRP. Competitive procurement of such generation resources creates an opportunity for ratepayer savings.

Action Plan for IRP Implementation

23. It is reasonable to require DESC to include a three-year Action Plan in its Modified 2020 IRP and in future IRPs. The three-year Action Plan should identify and describe the steps DESC will take to implement its IRP during that three-year period. This Action Plan

should include a graphical representation of the planned sequence of actions.

V. REVIEW OF THE EVIDENCE AND EVIDENTIARY CONCLUSIONS

A. Timing of Changes to IRP Methodologies

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NOS. 1-2

The evidence in support of these findings of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

Act 62 requires that a new, comprehensive IRP be prepared and submitted to the Commission for review at least every three years. S.C. Code Ann. § 58-37-40(A). IRP Updates must be prepared annually. *Id.* § 58-37-40(D). If the Commission rejects or modifies a proposed IRP, the utility must prepare and submit for approval, within sixty (60) days after the date of the final order, a revised plan addressing concerns identified by the Commission and incorporating commission-mandated revisions. *Id.* § 58-37-40(C)(2).

In this Order, the Commission is requiring DESC to make a number of changes to its IRP methodologies[5] that can be swiftly implemented and reflected in a revised plan (the "Modified 2020 IRP") that the Commission will require the Company to file within sixty (60) days of the date of the final Order, pursuant to S.C. Code Ann. § 58-37-40(C)(3). Other changes cannot be implemented so quickly, either because of their complexity or because they will require input from stakeholders. This includes in particular a number of important changes that ORS maintains that the Company must make to its IRP methodologies, as well as a number of changes that the Company has already agreed to implement on ORS's recommendation. (Tr. p. 751, l. 17 -p. 753, l. 8.) (Commissioner questions to ORS Witness Hayet)].

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[5] By "IRP methodologies," the Commission refers to the entire set of assumptions, modeling methods, and other choices that go into preparing the IRP.

Act 62 requires each electric utility to prepare a new IRP at least every three years, and to file annual updates to the IRP in other years. S.C. Code Ann. § 58-37-40(A), (D)(1). DESC indicated at the hearing that it is already working on the 2021 IRP Update and that it plans to file the 2021 Update in February 2021. All of the changes that the Commission is requiring to be implemented in the Modified 2020 IRP must also be reflected in the 2021 – and future - IRP Updates and IRPs.

However, the "long-term" changes the Commission references above – which may fundamentally change the Company's approach to preparing IRPs – are not appropriate for implementation in the 2021 IRP Update. It is equally not always appropriate to wait until 2023 to implement these changes in a full IRP subject to scrutiny by intervenors and the Commission. That is simply too long to wait, given the critical importance of sound integrated resource planning and the fact that these changes would fundamentally change DESC's methods for devising its IRP. Therefore, required changes have been allocated to the current Modified IRP, the 2021 Update, the 2022 Update, and the 2023 IRP as deemed feasible by the Commission. This is consistent with ORS's expressed preference that the Company make these important changes "sooner rather than later," (Tr. p. 752, l. 21 – p. 753, l.8.) and is well within the Commission's authority to require under Act 62.

As discussed below, a number of the required long-term changes to DESC's IRP methodologies (e.g. the implementation of capacity expansion modeling and adoption of risk metrics) will require meaningful input from stakeholders to be implemented in a manner consistent with Act 62. Therefore, the Commission will direct DESC to convene an ongoing IRP Stakeholder Process, through which DESC and other stakeholders can work collaboratively to address the issues identified herein and others that may arise from time to time as DESC's methods and processes for devising IRPs under Act 62 evolve. Stakeholders to the IRP actions should be comprised of representatives from multiple interest groups, to include residential and industrial classes of ratepayers and the ORS, should the ORS choose to participate. The stakeholder process should discuss selection and implementation of capacity expansion modeling software in the IRP development process; implementation of risk metrics and other measures to address ratepayer risk in the IRP development process; comprehensive retirement analysis of Dominion coal plants; and any other issues, as agreed on by the parties to the stakeholder process.

B. Use of Capacity Expansion Modeling

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 3

Summary of the Evidence

The evidence in support of this finding of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

DESC witness Eric H. Bell described the process by which the Company developed its candidate resource plans. The Company first identified generation resources and technologies and combined them into eight potential resource plans. DESC then applied three different demand-side management scenarios and scheduled resource additions to meet reserve margin requirements. (Tr. p. 65.24, l. 11 - 65.25, l. 6.) DESC witness Joseph Lynch testified that DESC used the PROSYM model to analyze the production costs of the various plans and used an Excel-based model to calculate the revenue requirements of the various plans. (Tr. p. 563, l. 22 – 564, l. 7.) Mr. Lynch testified that this was the same combination of models that was used to support the decision to complete construction of the new V.C. Summer nuclear units. (Tr. p. 563, p. ll. 13 -24.)

SCSBA witness Kenneth Sercy characterized DESC's approach to planning as a "needle-in-a-haystack" strategy because without a capacity expansion model, there are millions of possible plans and it will be difficult to identify the best one. (Tr. p. 637, ll. 6-14.) Similarly, the report by ORS's consultant, J. Kennedy and Associates, Inc. ("ORS Report"), stated that the Company's approach "limited the resource planning analyses to only those eight (8) RPs confected by the Company and the related sensitivities. There may be a lower cost RP than any of the eight RPs presented." (HE. 20, Ex. AMS-1, p. 64.)

Witness Sercy testified that a common approach to designing candidate resource plans is the use of a capacity expansion model.[6] Capacity expansion models are computer models that simulate generation and transmission capacity investment, given assumptions about future electricity demand, fuel prices, technology cost and performance, and policy and regulation. With capacity expansion modeling, the IRP process is not restricted to considering a limited set of hand-picked candidate resource plans. Instead, the utility can test every possible combination of resource deployment and retirements to determine which scenarios optimally meet the goals of the IRP process. (Tr. p. 607.11. ll.15-20.) As explained in the ORS Report, "[a]n optimization model would determine not only the optimal type of resource addition, but also the optimal timing of those additions." (HE. 20, Ex. AMS-1, p. 64.) Similarly, the Charles River Associates Report ("CRA Report") stated that "not utilizing a model with LTCE [long-term capacity expansion] functionality limits the portfolio options to a pre-defined list with pre-determined addition and retirement years. LTCE optimization would likely provide added insight into the DESC portfolio as it relates to early retirement options, the impact of new resource timing, and varying combinations of new resources. An LTCE simultaneously tests all possible combinations of these

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[6] Various witnesses also referred to this type of model as a "resource optimization model," (DESC witness Bell, Tr. p. 117, ll. 1-2), a "least cost optimization model," (ORS witness Hayet, Tr. pp. 748.17, l. 12 - 748.18, l. 18), or a "least cost optimization expansion planning model" (DESC witness Neely, Tr. p. 297.33, 13- 14).

factors under differing load, fuel, and policy environments which could potentially identify cost savings or portfolio risks which would otherwise not be apparent." (HE. 1, Ex. EHB-2, p. 59.) Accordingly, the CRA report recommended that DESC "consider incorporating another tool that allows for least cost optimization of capacity expansion." (HE. 1, Ex. EHB-2, p. 11.)

CCL and SACE witness Anna Sommer, who testified that she had reviewed dozens, possibly as many as a hundred IRPs, using a variety of different software packages, testified regarding IRP modeling. (Tr. p. 482, ll. 18-22.) According to Ms. Sommer, DESC's use of the PROSYM production cost model rather than a capacity expansion model does not comport with standard industry practice for a utility of its size. Ms. Sommer testified that she did not believe that a utility of DESC's size can accurately conduct the detailed portfolio analysis using multiple scenarios and sensitivities described in subsection (B)(1)(e) without a capacity expansion model that has the capability to select resources and optimize for a particular outcome. (Tr. p. 476.13, ll. 22-27.) Ms. Sommer further testified that she did not believe that DESC's use of PROSYM for its 2020 IRP comports with standard industry practice and may render its analysis deficient under subsection S C. Code Ann. §58-37-40 (B)(1)(E) of the EFA.[7] (Tr. p. 476.15, ll. 13-15.)

Witness Sommer testified that where resource choices are not limited to one or two types by applicable energy policy, using a capacity expansion model is standard industry practice. A capacity expansion model simulates not just the dispatch of generators as PROSYM does, but also has the capability to select and retire units based on economics. Because of the complexity of capacity expansion optimization, it is not possible to infer the best combination of resource additions, the most economic retirement dates, and the ways in which those resource choices

[7] "EFA" refers to the South Carolina Energy Freedom Act, which is officially known as 2019 Act No. 62 effective May 16, 2019.

might change using just a production cost model like PROSYM. (Tr. p. 476.14, ll. 3-11.)

ORS witness Hayet likewise testified that adding a capacity expansion model is considered by ORS to be a "high priority item," and that the new model should be implemented prior to the next IRP, but no later than the next comprehensive IRP in 2023. (Tr., p. 742.13, ll. 15-17.)

Witness Sommer recommended that the Commission consider directing DESC to engage stakeholders in a collaborative process to choose a capacity expansion model to use in its next IRP. According to SCSBA witness Sercy, the choice of software is an important one, which hinges on the capabilities needed to ensure the model is providing valuable information to the IRP process, given South Carolina policy and regulatory directives and the particular circumstances of DESC's system. While witness Sercy testified that he supports implementing capacity expansion modeling within DESC's IRP process as soon as possible, due diligence is necessary in identifying the best software to use. (Tr. p. 615.30, ll. 3-7.) As an example, Ms. Sommer pointed to a collaborative process to select a capacity expansion model for DTE Energy in Michigan, in which she participated and found to be well run and informative. The list of evaluation criteria developed for how DTE Energy would select an IRP model was attached to Ms. Sommer's direct testimony as Exhibit AS-2. (Tr. p. 476.15, ll. 15-21; HE. 6, Ex. AS-2.)

DESC witness Neely testified that the Company sees value in having a resource optimization model as a tool to create and evaluate resource plans. (Tr. p. 308, ll. 15-19.) DESC witness Bell testified that the Company is currently implementing a least-cost optimization model to use in future IRPs. (Tr., p. 115, ll. 15-18.) The generation planning department in Richmond for Dominion Energy Virginia has already selected the PLEXOS model for use across all of Dominion Energy's electric operating units. (Tr. pp. 150, l. 12 - 151, l. 1.) Mr. Bell testified that

PLEXOS costs hundreds of thousands of dollars to access. (Tr. p. 151, ll. 2-4.) Although the Company's goal is to have that model implemented for the 2021 update, witness Bell stated that it looks like such goal will be difficult to achieve. (Tr., p. 115, ll. 19-23.)

According to Witness Sommer, DESC offered no assurance that the Company will provide transparency into its modeling. (Tr. p. 479.) Witness Sommer also identified shortcomings of the PLEXOS model that Dominion has chosen for its operating utilities; for example, the PLEXOS interface is "clunky and not particularly intuitive," (Tr. p. 499, ll. 7-8.), and the model has limitations on modeling of load and representation of time, (Tr. pp. 499-500.). In addition, Ms. Sommer identified "transparency barriers" associated with PLEXOS. (Tr. p. 503,ll. 13-15.) For example, it is unclear whether inputs and outputs from PLEXOS can be exported in a useable format, (Tr. p. 502, ll. 3-7.), and the cost of a license is prohibitively expensive, (Tr. p. 503, ll. 11-13). In contrast, Ms. Sommer testified that other models are available at a lower licensing fee and allow information to be exported, including the model manual. (Tr. p. 503, ll. 16-24.)

In her surrebuttal testimony, Witness Sommer continued to recommend that the Commission take the following steps to ensure that Dominion's IRP modeling is transparent and accessible to stakeholders: order DESC to engage in a collaborative process to choose a capacity expansion model for future IRPs; order DESC to negotiate a discounted, project-based fee that permits interested intervenors the ability to perform their own modeling runs in the same software package as DESC during the pendency of its IRP cases; consider whether to direct DESC to absorb the cost of these licensing fees; and order DESC to file, in electronic spreadsheet format, the modeling inputs (including settings) and outputs, assumptions, any post-processing spreadsheets (e.g. to create the revenue requirements), and the model manual as a part of IRP filings going forward. (Tr. p. 479.5.)

Commission Conclusions

The evidence showed that in developing the 2020 IRP, DESC did not use capacity expansion modeling software, which is widely used in the electric utility industry. Instead, the Company chose a set of resource plans and then analyzed the cost of those plans. The Commission credits the testimony of SBA witness Sercy and CCL/SACE witness Sommer in finding that this "needle-in-a-haystack" approach fell short of industry best practices, and means that the Company possibly did not identify the most reasonable and prudent plan that would minimize costs and risks to ratepayers.

The Commission concludes that it is reasonable to require DESC to adopt and implement the use of capacity expansion software starting no later than with the development of the 2022 IRP Update. The Commission appreciates DESC's commitment to implement a capacity expansion model in developing future IRPs, and recognizes that Dominion Energy has selected the PLEXOS model for its operating utilities. Given the importance of the choice of model, however, the Commission concludes that it is reasonable to require DESC to engage interested parties in this proceeding in a collaborative process to choose a capacity expansion model for the 2022 IRP Update and future IRP proceedings. In their deliberations, collaborative members shall consider the criteria set forth in Hearing Exhibit 6, Exhibit AS-2, with particular attention to the criteria numbered 1-7 and 9-12. Finally, contemporaneously with the filing of each future IRP, DESC shall make available, without the need for a data request, the modeling inputs (including settings) and outputs, assumptions, any post-processing spreadsheets (e.g. to create the revenue requirements) in electronic spreadsheet format, and the model manual.

C. **DESC's Candidate Resource Plans**

1. **Failure to Model Renewable Additions Prior to 2026**

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 4

Summary of the Evidence

The evidence in support of this finding of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

SCSBA Witness Sercy testified that of the eight candidate resource plans included in the Proposed IRP, none included any proposal to add renewables or energy storage before 2026. (Tr. p. 607.13, ll. 3-6.) Mr. Sercy argued that a candidate resource plan with earlier clean energy additions might save ratepayers money and/or expose them to less risk than any of the candidate plans in the Proposed IRP, and that DESC should be required to analyze the potential benefits of plans with earlier clean energy additions. (Tr. p. 607.13, ll. 7-12.) SCSBA had proposed some plans with early additions of clean energy to DESC during the IRP development process, but DESC did not compare those plans to its candidate plans. (Tr. pp. 607.13-14.)

Mr. Sercy also noted that solar and/or storage projects coming online in 2023 might be able to take advantage of the 22% federal Investment Tax "steps down" to 10%. (Tr. p. 607.17, l. 10 – p. 607-18, l. 6.) Projects with access to the 22% Investment Tax Credit ("ITC") could be constructed at lower overall cost and could potentially deliver greater value to ratepayers.

Mr. Sercy recommended that DESC be required to evaluate additional resource plans that would include additions of solar and/or storage in 2023 instead of 2026. Specifically, Mr. Sercy proposed two variations on DESC's RP7 plan, which he dubbed RP7-A and RP7-B. RP7-A would modify the original RP7 expansion plan by adding 400 MW of flexible solar PPAs in 2023 instead of 2026, and by eliminating the battery storage addition from that plan. RP7-B would modify the original RP7 expansion plan by adding the 400 MW of flexible solar PPAs in 2023 instead of 2026, and by adding the 100 MW battery storage in 2023 instead of 2026. The battery storage addition should be modeled as battery storage PPAs that are paired with solar PV and are thus able to utilize the federal ITC. (Tr., pp. 607.53, l. 23 – 607.54, l. 9.)

DESC's witnesses did not respond to Mr. Sercy's testimony regarding the failure of the Proposed IRP to include any resource plans that add renewables or storage before 2026, and did not oppose Mr. Sercy's recommendation that the Company be required to model additional resource plans as suggested by Mr. Sercy. (See pp. 615.4 - 615.5 (Sercy Surrebuttal, summarizing SCSBA recommendations not responded to by DESC).)

DESC Witness Neely did concede in his rebuttal testimony the fact that the Company did not model the addition of solar or storage before 2026, which meant that the pricing assumptions it developed for the Proposed IRP assumed that solar and storage developers would not be able to use the 22% ITC. (Tr. p. 297.18.)

On surrebuttal, Mr. Sercy pointed out that by calling for no action prior to 2026, DESC's candidate resource plans would effectively forego any opportunity to add renewables to the system in the near term. While solar PV and battery storage have relatively short construction lead times, bringing these resources online also requires that projects move through the interconnection process, and procurement activities such as RFPs take time as well and typically require regulatory oversight. If such steps are not initiated in the near future, bringing solar PPAs onto DESC's system by 2023, for example, will become infeasible. (Tr. pp. 615.7, l. 15 - 615.8, l. 7.)

Mr. Sercy also noted on surrebuttal that DESC was able to complete a substantial amount of additional modeling work in support of the IRP Supplement provided with its rebuttal testimony. In support of its rebuttal testimony, DESC presented over 50% more cost calculations for candidate resource plans than it presented for its original IRP and direct testimony. (Tr. pp. 615.2-615.3)

At the hearing, DESC Witness Neely conceded that by declining to analyze any resource plan with solar or storage additions before 2026, the Company excluded potentially lower-cost solar or storage resources from consideration. (Tr. p. 336, ll.6- 10 ("Q. But by declining to analyze a plan with solar or storage coming on-line before 2026, the Company excluded potentially lower-cost solar or storage resources from consideration, didn't it? A. It did."))

Mr. Neely did testify that the Company did not consider any resource plan adding renewables before 2026 because the Company does not have an identified capacity need before then. (Tr. p. 380, ll. 12-21.) However, Mr. Neely acknowledged that even in the absence of a need for additional capacity, the Company could still save money for ratepayers by procuring energy from independent power producers, if the cost of those PPAs was less than the Company's cost of generation. (Tr. pp. 381, l.3 - 382, l.24.)[8] He also testified that if there were a renewable resource that could deliver energy at a lower price than the utility's per-kWh cost of generation, the Company "would want to know that." (Tr. p. 383, ll. 19-24.)

DESC Witness Bell testified at the hearing that Dominion Energy, DESC's parent company, announced in February 2020 that it had committed to achieving net zero carbon emissions by 2050, and that the Company had touted that commitment in prior filings with this Commission. (Tr. p. 100, ll. 14-19.) That net zero carbon commitment is referenced in the

[8] DESC witness Lynch also testified that capacity even above the Company's planning reserve margin could still be useful, and that "the more capacity you have, the more flexibility and ability to produce operating . . . , production costs, keep them lower than they would otherwise be. So the fuel costs to customers would be lower the more capacity you have, gives you more options in the dispatch." (Tr., p. 579, ll.17-23.)

Proposed IRP, as well. (HE. 1, Ex. EHB-1, p. 29; Tr. at p. 104.) However, Mr. Bell also acknowledged that the Proposed IRP actually does not include any plan for making good on that commitment. (Tr., p. 105.). Finally, Mr. Bell acknowledged under cross examination that the Company agrees that Act 62 established that South Carolina has a policy of encouraging renewable energy. (Tr. p. 100).

Commission Conclusions

In consideration of the above evidence, the Commission concludes that because it fails to analyze any candidate resource plans that would add solar or storage before 2026, the Proposed IRP does not meet Act 62's requirement that it include resource portfolios that "fairly evaluat[e] the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations." S.C. Code Ann. § 58-37-40(B)(1)(e)(Supp. 2019). The evidence demonstrates that procurement of solar and/or storage starting as early as 2023 could result in cost savings to ratepayers, even in the absence of any need for additional capacity on DESC's system. DESC did not oppose SCSBA's request that it be required to model additional scenarios, and did not introduce any evidence that it would be burdensome or impractical to conduct additional modeling for a Modified IRP (and indeed, the amount of modeling the utility was able to perform in a limited time for purposes of preparing the IRP Supplement shows that this is well within the range of possibility).

Even if the Company had not conceded the point, the evidence provided by Intervenors is persuasive on this issue. The Commission is hopeful that modeling these scenarios will provide, at least, some potential options for making good on the Company's net-zero carbon commitment, currently lacking in the Proposed IRP.

The Commission will therefore require DESC, in its Modified 2020 IRP, to model the additional resource plans (RP7-A and RP7-B) proposed by SCSBA Witness Sercy, and to re-model resource plan RP2 for comparison purposes. In modeling the costs of those plans, DESC must incorporate all the other modeling and other adjustments discussed elsewhere in this Order. As discussed below, the Commission will also direct DESC to model those resource plans with the cost sensitivities proposed by Mr. Sercy.

As it relates to the ITC, DESC shall be required to document how it is or is not prudent to take advantage of the solar ITC or implement a plant to take advantage of the solar ITC. This documentation shall be required beginning with its 2022 IRP Update.

2. Failure to Model Coal Retirement Prior to 2028

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NOS. 4 & 5

Summary of the Evidence

The evidence supporting these findings of fact and conclusions is contained in the Company's 2020 IRP and IRP Supplement, testimony and exhibits of DESC Witnesses Eric Bell and James Neely, testimony and exhibits of Sierra Club Witness Derek Stenclik and the testimony and exhibits of ORS Witnesses Sandonato and Hayet.

Company Witness Bell testified that DESC considered facility retirements in its IRP by evaluating the costs and sensitivities related to unit retirements at Wateree Station, McMeekin Station, Urquhart Unit 3 and Williams Station in Resource Plans 3, 4, and 8. (Tr., p. 50.20, ll. 4-11.) RP3 included the retirement of Wateree in 2028; RP4 included the retirement of Urquhart 3 and McMeekin 1 and 2 in 2028; and RP8 included the retirement of Wateree and Williams in 2028. (HE. 1, Ex. EHB-1 pp.40-41.) The IRP also stated that DESC is evaluating the possible replacement of existing peaking generation assets, such as McMeekin Units 1 and 2 and Urquhart Unit 3, (HE. 1, Ex. EHB-1, p. 34), but that no major changes to the generation fleet are required in the near term. (HE. 1, EHB-1, p. 3.) On cross-examination by Sierra Club, Company Witness Bell stated that the evaluations they conducted for the IRP were not a full retirement study, and he agreed that a retirement study would need to include all costs and benefits associated with near and mid-term retirement dates such as capital expenditures, environmental expenditures and consider all available resources as potential replacements. (Tr. pp. 131, l.:24 - 132, l. 11.)

Sierra Club Witness Stenclik presented independent modeling using PLEXOS to evaluate alternative resource portfolio options. (Tr. p. 705.28.) Witness Stenclik recreated the Company's model and process using the Company's own input assumptions with the exception of: capital cost assumptions for ICTs and battery storage were updated to industry standards; interconnection cost of battery storage and solar PV were made consistent; battery storage economic life was updated from 10-15 years; load forecast and load profile. (Tr. pp. 705.29-30.) Witness Stenclik's modeling evaluated five different scenarios that retired the Williams and Wateree plants starting in 2026 and replacing them with solar and storage technology. (Tr. p. 705.31, ll. 4-5.) Mr. Stenclik's modeling results show that retiring Williams and Wateree in either 2026 or 2028 results in lower costs than the Company's preferred RP2, saving ratepayers approximately $14 million. (Tr. pp. 705.33-705.34, Tables 5-6.)

Sierra Club Witness Stenclik also discussed the risk of continued operation of DESC's coal plants including the reliability risks of aging infrastructure, need for increased generation flexibility, potential for more stringent federal or state environmental policy and cost uncertainty with Effluent Limitation Guidelines (ELG) upgrades. (Tr. pp. 705.23 - 705.27.) Witness Stenclik pointed to the recent Wateree 2 outage as an example of a coal plant reliability concern - a long duration forced outage due to an explosion in January 2020, which will keep Wateree 2 offline until 2022. (Tr. p. 705.23, ll.13-15; Tr. p. 414, ll.14:23.) Sierra Club Witness Stenclik also stated that generation flexibility is increasingly important due to increased variability from wind and solar, changing load patterns, and growing electrification trends which will require the Company's existing generation fleet to be operated in a more flexible manner, (Tr. p. 705.24, ll. 10-14), but the Company's coal fleet was designed instead to operate as a baseload unit with minimal cycling and though it may be able to change operations it will result in increased costs, and equipment degradation. (Tr. p. 705.24, ll. 15-19.) Replacing large coal plants with smaller, more dispersed, more flexible, and modular solar and storage systems can yield improved reliability and fuel diversity benefits. (Tr. p. 702, ll. 8-12.)

In response to the Company's Supplemental IRP and its modeling update, Sierra Club Witness Stenclik testified that he incorporated the changes from the Supplemental IRP into his model and the new results yielded a similar conclusion to his direct testimony – the earlier retirement of Williams and Wateree combined with replacement with solar and storage, which yields cost savings for the Company's ratepayers as compared to RP2. (Tr. pp. 711.9 – 711.11.) Witness Stenclik concluded that alternative portfolios, which the Company failed to evaluate, may be lower cost than the eight resource plans presented in the 2020 IRP and Supplemental IRP highlighting the importance of using capacity expansion planning tools. (Tr. p. 711.14, ll. 20-22.) Witness Stenclick recommended that the Company be required to consider alternative portfolios that retire Williams and Wateree early and replaces them with clean energy technology. In addition, Witness Stenclik recommended that the Commission open a new docket to address the retirement and replacement of Williams and Wateree. (Tr. pp. 705.36 – 705.37; p. 711.24.)

SCSBA Witness Sercy testified that since the Company did not evaluate the possibility of retiring a coal plant before 2028, it is unknown whether it might be good for ratepayers. (Tr. p. 647, ll. 15-16.) Witness Sercy also pointed out that the Company has not performed any recent analysis of potential coal retirements and that a comprehensive coal retirement analysis would provide valuable insight into the IRP development process, which could examine the economics of a wide range of retirement options. (Tr. p. 607.14, l. 20 – p. 607.15, l. 2.) Witness Sercy pointed to a recent order from the North Carolina Utilities Commission requiring Duke Energy Carolinas and Duke Energy Progress to perform an economic retirement analysis of aging coal plants as part of their next IRPs, including modeling the continued operation of the coal plants under least cost principles, by way of competition with alternative new resources, and including the full costs of disposal of coal combustion wastes. (Tr. p. 607.15, ll. 7-21.)

The ORS Report stated that the Company's depreciation study is approximately six years old and the Company had not reassessed the retirement dates in any recent comprehensive engineering or economic analysis. (HE. 20, Ex. AMS-1, p. 53.). The ORS Report also stated that the need to conduct a detailed retirement analysis was even more pressing considering the major outage at Wateree 2 where the Company did perform a limited retire/replace study, although as the report pointed out, the retire/replace study for Wateree 2 was not considered by the Company to be a comprehensive "retirement" study. (HE. 20, Ex. AMS-1, p. 54.) ORS Witness Hayet then recommended that the Company should conduct a detailed retirement analysis in the near future and that it should analyze all potential retirement units and be conducted prior to the next IRP, but no later than the next comprehensive IRP in 2023. (Tr. p. 742.12, ll. 3-9; HE. 20, p. 55.)

In response to ORS' recommendation to conduct a retirement analysis, Company Witness Bell testified that the Company plans to conduct detailed retirement studies for potential retirement candidates in the coming years. (Tr. p. 65.21, ll. 16-17.) Witness Bell went on to explain that retirement studies are time consuming, resource intensive and expensive and cannot be done all at once. (Tr. p. 65.21, ll. 18-20.) Witness Bell also testified that they did not model retirements of Williams and Wateree prior to 2028 because without a significant change in regulation or a need to spend significant capital, customers benefit from continuing to operate the generators they are already paying for and will continue to pay for after retirement. (Tr. p. 65.22, ll. 10-12.) On cross-examination by the Sierra Club, Witness Bell stated they do not know when they will complete a retirement study. (Tr. p. 133, ll. 14-18.) In response to a question from Commissioner Ervin, Company Witness Bell agreed that it would make sense to conduct a retirement analysis next year in order to have it by the next IRP in 2022 or 2023 so there would be data to make long-term decisions. (Tr. p. 162,ll. 2-15.) Company Witness Bell also agreed with Commissioner Ervin that it makes sense for the Commission to consider opening a separate docket to look at the coal-fired facilities. (Tr. p. 162, ll. 17-25.)

There was conflicting testimony from the Company's own witnesses regarding the timeline for compliance with the ELG rule. Company Witness Bell stated that the Company planned to explore the potential for a coal plant retirement before 2028, the last year coal plants can operate without addressing the ELG rule, (Tr. p. 65.22, l. 13), but the result would likely lead to a retirement coincident with ELG expenditures in 2028. (Tr. p. 65.23, ll. 9-11.) On cross-examination, Witness Bell admitted that he was unaware of a December 31, 2025, deadline to retrofit or upgrade Williams and Wateree to comply with the ELG rule and did not know when the Company would have to make a decision to retrofit the plants, but the Company planned to conduct a more detailed retirement analysis prior to making that decision. (Tr. p. 138, ll. 2-24.)

In contrast to the testimony of Company Witness Bell, Company Witness Neely testified that 2026 is the assumed year for installation of ELG. (Tr. p. 297.16, ll. 14-16.) On cross-examination, Witness Neely stated he realized the actual date for compliance to install the retrofits was December 31, 2025, and although he thought there were alternatives to installing the retrofits by 2025, he did not state what those alternatives were. (Tr. p. 405, ll. 6-12.) Witness Neely also testified that he did not know how long it would take to construct or install the retrofits but that ideally a decision would be made now whether to retrofit the plants if the retrofits have to occur by the end of 2025. (Tr., pp. 405, l.24; 406,l.23.) Witness Neely also testified that the costs to retrofit Williams and Wateree to comply with the ELG rule was $255.2 million, with a total revenue requirement for the ELG costs of $900 million. (Tr. pp. 406,l. 24 - 407, l. 25.)

In response to Company Witnesses Bell and Neely's testimony, Sierra Club Witness Stenclik testified that the retirement studies must start as soon as possible, and needed to be not only comprehensive but also include stakeholder involvement. (Tr. pp. 711.22, l.3. - 711.23, l.5.) Witness Stenclik also discussed the shortening time window for the Company to conduct the retirement analysis due to the upcoming deadline to comply with the ELG rules and that a delayed retirement analysis could lead to an unnecessarily abrupt transition away from coal which could affect plant employees and local communities, which is why he recommends starting the retirement analysis as soon as possible. (Tr., p. 711.23, ll. 6-15.)

Commission Conclusions

In consideration of the above evidence, the Commission concludes that because it failed to properly analyze facility retirements, the Proposed IRP does not meet Act 62's requirement that it consider facility retirement assumptions. S.C. Code Ann. § 58-37- 40(B)(1)(h). The evidence shows that the retirements included in Resource Plans 3, 4 and 8 were not based on a robust retirement analysis, assessing all the costs and benefits associated with near and mid-term retirement dates such as capital expenditures, environmental expenditures while considering all available resources as potential replacements. Based on the modeling results of Sierra Club Witness Stenclik, there are other, equally viable, less expensive scenarios that the Company failed to evaluate, all of which included the early retirement of Williams and Wateree. We agree with Sierra Club Witness Stenclick's and SBA Witness Sercy's recommendation to require the Company to reanalyze its IRP portfolios, consider alternative portfolios that retire Williams and Wateree early and replaces them with clean energy technology.

The Commission also agrees with the recommendation of ORS Witnesses Sandonato and Hayet, SBA Witness Sercy and Sierra Club Witness Stenclik that a retirement analysis must be completed as soon as possible. While ELG costs themselves are not at issue in this IRP, these costs must be included in any retirement analysis conducted by the Company, and a retirement analysis must be conducted prior to making any decisions regarding whether to retrofit the Williams and Wateree units to comply with the ELG rule. In order for the Company to meet the December 31, 2025, deadline to retrofit Williams and Wateree, the Commission is opening a new docket to assess the retirement and replacement of the Company's coal plants. This proceeding will evaluate the reliability risks and environmental costs of continued operation of the coal plants as well as options, informed by resource bids, to replace legacy coal technology with state-of-the-art clean energy. DESC is required to perform a comprehensive coal retirement analysis to inform development of its 2022 IRP Update, and to solicit parties' recommendations on guidelines for performing this analysis and approve a set of guidelines prior to DESC's 2022 IRP Update development process via the ongoing IRP Stakeholder Process.

Relatedly, the Company shall provide more information on the outage, including, but not limited to:

- Document the $10 million cost limit.
- Identify the insurance company and its rating.
- Identify the builder/contractor and its financial security.

- Identify the turbine builder and its financial security.
- Provide a detailed timeline for the project.
- Provide a backup plan if the project fails.
- Provide additional guidance regarding next steps, retirement, repairs, or the like.
- Any planned actions should be reflected in the Short-Term Action Plan filed by Dominion.

3. Failure to Include DSM or Purchased Power as a Resource Option

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 6

Summary of the Evidence

The evidence in support of this finding of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

SCSBA Witness Sercy testified that DESC failed to include DSM or purchased power as potential resource options that could be incorporated into candidate resource plans. With respect to DSM, DESC instead performed a DSM sensitivity whereby the costs of the eight candidate resource plans were calculated within one scenario (base gas, \$0 CO2) with different levels of DSM reflected in decrements to the load forecast. As a result, DSM was not fully evaluated because it was not modeled across all gas and CO2 price scenarios. (Tr. pp. 607.19 – 607.20.)

Witness Sercy noted that Act 62 specifies that IRPs "must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of.... sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks." Further, industry best practices for considering DSM within IRPs include creating DSM supply curves that identify specific quantities of DSM and their costs, which are then allowed to compete against supply-side resources within the cost modeling. (*Id.*)

Witness Sercy further testified that power purchases were not considered by DESC as a full resource option that could be incorporated into candidate resource plans for evaluation across scenarios. Witness Sercy stated that off-system power imports are an available means of meeting capacity and energy needs and could play a role in a reasonable and prudent resource plan, and that many utilities import power for multiple years or on a long-term basis as part of their generation mix. Witness Sercy noted that SCSBA plan 3 illustrates how capacity purchases could potentially be used as a low-cost "bridge" to enable accelerated coal retirement before taking advantage of expected continueddeclines in battery storage costs. (*Id.*)

Witness Sercy recommended that in its Modified IRP DESC should be required to include DSM and purchased power as resource options that are incorporated into candidate resource plans and evaluated across multiple scenarios. (Tr. p. 607.22.)

DESC Witness Neely testified that DESC did not include off-system purchases as a resource option because they create a system reliability risk, are surveyed for price competitiveness via request for proposal as part of the Siting Act procedures, and have uncertain future cost and availability profiles that create modeling challenges. (Tr. pp. 297.13 – 297.14.) DESC Witness Neely also described additional DSM modeling that DESC completed in its IRP Supplement. The IRP Supplement includes each of the eight DESC resource plans against all three DSM cases, all three gas price cases, and both CO2 assumptions. (*Id.*)

Witness Sercy testified in surrebuttal that, with respect to purchased power, a large portion of the U.S. electricity sector is made up of utilities whose power supply comes entirely or mostly from long-term power purchase, and that with industry-standard contract provisions in place, power purchases are a demonstrably reliable supply choice. Witness Sercy also noted that the

Company's next Siting Act application will not be submitted for more than a decade. Finally, Witness Sercy stated that DESC's 2020 IRP already makes cost and availability assumptions for power purchases, including those modeled many years into the future, and that reasonable assumptions can be identified for long-term purchases just as they can be identified for short-term purchases. (Tr. pp. 615.21- 615.22.)

The ORS Report noted that "it is not inappropriate for a utility to include capacity purchases in its IRP or to actually make capacity purchases." (HE. 20, Ex. AMS-1, p. 60; Tr. p. 615.22, ll. 3-4.).

Regarding DSM, Witness Sercy stated that DESC did not directly respond to his direct testimony critiquing DESC's decision not to include DSM as a resource option. Witness Sercy acknowledged that DESC produced cost results for its High DSM and Low DSM cases across all six gas-CO2 scenarios, but stated that given how DSM was modeled by DESC, it is possible that the candidate plans are still not designed in an optimal way in relation to the DSM components of the plan. Witness Sercy stated that, nonetheless, DESC's updated DSM results demonstrated that higher levels of DSM reduced the risk of any given candidate plan. (Tr. pp. 615.32 – 615.33.)

Commission Conclusions

The Commission agrees with SCSBA Witness Sercy that DESC should include both DSM and purchased power as potential resource options that could be incorporated into candidate resource plans. The Commission notes the DESC did not directly respond to Witness Sercy's testimony regarding the inclusion of DSM as a potential resource option, and that in order to fully evaluate resource options available to DESC and its customers, DESC should include DSM as a resource option in the 2021 IRP Update – if achievable - or 2022 IRP Update and future IRPs. The selection of a capacity expansion model, discussed elsewhere in this Order, should include consideration of the model's capability to select DSM as a resource.

The Commission determines that, in addition to modeling DSM as a resource, a rate rider incentive to reduce the peak demand (or "Shave the Peak") shall be evaluated and shall be documented.

The Commission also agrees that DESC should include purchased power as a resource option in the 2021 IRP Update – if achievable – or 2022 IRP Update and future IRPs. The Commission does not find persuasive DESC's stated reasons for excluding purchased power as a resource option. Off-system power imports are an available means of meeting capacity and energy needs and could play a role in a reasonable and prudent resource plan, and the Commission will require DESC to include both purchased power and DSM as resource options in the 2022 IRP Update and future IRPs.

The value, or cost, and availability of purchased power as a resource to fulfill projected loads should be fully analyzed and the realistic utilization of such resources should be explained. It is expected that Dominion will consider the input of stakeholders in its evaluation of the purchased power and DSM modeling.

4. <u>Design of Resource Plans to Meet Only Base Reserve Margin Rather Than Full Peaking Reserve Margin</u>

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 7

<u>Summary of the Evidence</u>

The evidence in support of this finding of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

SCSBA Witness Sercy testified that DESC uses its base reserve margin targets of 12% summer and 14% winter, instead of its peaking reserve margin targets (14% summer, 21%

winter), when constructing its candidate resource plans. Witness Sercy noted that DESC then supplements each candidate resource plan with short-term power purchases in order to reach the full peaking reserve margin targets. Witness Sercy testified that this approach effectively excludes hundreds of MWs from the IRP process where candidate resource plans are modeled and compared to one another, and he noted that the PSC ruled on this issue previously and determined that the 21% peaking reserve margin was the appropriate target to use when setting avoided cost rates. (Tr. pp. 607.20 – 607.21.)

DESC Witness Lynch responded to Witness Sercy by stating that planning the system to require a 21% reserve margin to be supplied by base capacity resources would risk burdening customers with unnecessary costs. Witness Lynch stated that limiting planning to include short-term purchases, additional demand-response, or upgrades to existing peaking resources will identify the lowest cost resources. (Tr. pp. 559.23- 559.24.)

Witness Sercy stated in surrebuttal testimony that the options DESC assumed are available for meeting its additional peaking reserve margin, limited to short-term purchases, additional demand response, and upgrades to existing peaking resources, are highly limited, and that DESC does not allow the vast majority of potential resource options to compete. Witness Sercy stated that the full peaking reserve margin target should be used in the process whereby candidate resource plans are fairly evaluated against one another for meeting customer needs. By failing to allow candidate resource plans to fully compete against one another, DESC may overlook more economic means of meeting the peaking reserve need. Witness Sercy also noted that the use of a capacity expansion model could substantially ease the adoption of his recommendation (Tr. pp. 615.19 – 615.20.) Witness Sercy recommended that for its next IRP, DESC should be required to build candidate resource plans to meet its full peaking reserve margin target, and the resource plan analysis should determine what type of resources best meet the peaking increment. (Tr. p. 615.46.)

The CRA Report stated that "DESC may also consider performing portfolio analysis against the full peaking reserve requirement in its future IRP in order to test whether such 'short duration' resources [such as demand response, seasonal capacity purchases, peaking generator, and storage resources] are a cost-effective part of the portfolio, subject to other system and portfolio design constraints." (HE. 1, Ex. EHB-2, p. 49.)

ORS stated that in the future, DESC should employ an economic decision-making process in deciding whether to add short term capacity purchases or some other type of resource in its IRP. (HE. 1, Ex. EHB-2, p. 60.)

Commission Conclusions

The Commission agrees with SCSBA Witness Sercy that DESC should be required to build candidate resource plans to meet DESC's full peaking reserve margin target, and the resource plan analysis should determine what type of resources best meet the peaking increment, including all available resources. DESC's current peaking reserve margin targets are 14% summer, 21% winter. It is appropriate for DESC, starting with its 2021 IRP Update, to systematically compare resource options for meeting its peaking reserve margin increment, including all available resources, rather than limiting available resources to a narrow subset.

The Commission expects that reliability and resiliency considerations must be presented and such presentation must incorporate detailed discussion of the reserve requirements needed by the utility, including a traditional Loss of Load Expectation study.

D. Modeling of Candidate Resource Plans

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 8

1. Solar PV PPA Cost Assumptions

Summary of Evidence

The evidence in support of this finding of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

Witness Sercy testified that DESC used unreasonable assumptions for solar PV and energy storage cost and system value in the candidate resource plans that include solar PV and energy storage. Specifically, while Resource Plan 7 ("RP7") included 400 MW of 20- year solar PPAs coming online in 2026, DESC assumed that the cost of these PPAs would be $49.05/MWh based on its adjusted version of the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") medium price projections. Mr. Sercy testified that DESC's adjusted ATB price model is inconsistent with actual Southeastern solar PV market prices in recent years. (Tr. p. 607.16.) For example, DESC's price model calculates a 20-year PPA price of $47.77/MWh for a 2019 project, but the 2019 North Carolina Competitive Procurement of Renewable Energy ("CPRE") Tranche 1 average winning bid for a 20-year solar PPA was $38/MWh – a difference of more than 20%. (*Id.*) Further, a 2019 Request for Information ("RFI") issued by Santee Cooper found a weighted average levelized cost of less than $28/MWh for 20-year solar PPAs, and the General Assembly subsequently authorized Santee Cooper to move forward with the procurement of up to 500 MW of solar PV based on the RFI results. (Tr. p. 607.17.) Finally, executed PPAs under South Carolina Electric & Gas Company avoided cost tariffs available in 2017 with blended rates of $34/MWh have been filed with this Commission. (Tr. p. 607.17) These prices are significantly lower than the prices assumed by DESC in its

Proposed IRP and show them to be incorrect. DESC's faulty assumptions significantly overestimated the relative cost of solar PV PPAs compared to other potential resources.

Mr. Sercy also agreed with the CRA Report's identification of another incorrect assumption within these PPA pricing models related to the federal solar ITC. CRA observed that DESC incorrectly "assumed that full ITC qualification ends in 2019, and the ITC steps down to 10% from 2020-2022," even though developers "can safe harbor ITC for up to four years if they incur at 15 least five percent of the project costs in that year and receive the full ITC for that year." (Tr. p. 607.17.) That means a project safe-harbored in 2019 could enter into service in 2023 and still receive a 30% ITC. (*Id.*) Thus, DESC should have assumed that project developers are able to safe-harbor the 22% ITC available in 2021. (*Id.*) For the purposes of DESC's 2020 IRP, Witness Sercy concluded that the most reasonable solar PPA price curve would be the ATB low case adjusted to safe-harbor the 22% ITC, yielding a 2026 PPA price of $36.19/MWh – approximately $13/MWh *lower* than DESC assumed for its RP7 modeling run. (Tr. p. 607.18.) The inflated PPA price assumption used by DESC equated to an extra cost of $10.7 million per year during each year of the 20-year PPAs within RP7. (*Id.*)

DESC Witness Neely made certain adjustments to the Company's cost estimates in his rebuttal testimony, but the corrections failed to remedy the errors pointed out by Witness Sercy. Mr. Neely's rebuttal testimony describes a correction to the projected capital cost figures for solar PV and battery storage, prompted by an ORS recommendation, but in his surrebuttal testimony Mr. Sercy pointed out that these revised projections must be applied to an appropriate set of starting inputs, namely the NREL ATB Low Case rather than the Mid Case, consistent with the above evidence of actual pricing and the need to calibrate the pricing model to reflect real-world market data. (Tr. pp. 615.12 – 615.13.) Applying Mr. Neely's correction to the solar PV Low

Case PPA pricing model, using appropriate ITC safe harbor assumptions, and correcting for the Southeastern region's low installed costs (10% below the national median), Mr. Sercy calculated a 2023 PPA price of $38.94/MWh. (*Id.*) Because a 20-year PPA initiated in 2023 would expire in 2043 and would need to be replaced with a new 20-year PPA, Sercy also calculated a 2043 PPA price of $34.93/MWh. (*Id.*)

DESC Witness Neely, when asked by Commissioner Belser about the impact of using of lower PPA prices, acknowledged that doing so would lower the net present value cost of resource plans with the PPA element, but stated that he was unable to gauge the impact of that reduction without further modeling runs using the updated PPA costs. (Tr. p. 424.) During the hearing, Witness Sercy reiterated that use of the incorrect PPA prices was unreasonable and should be remedied to produce a reliable IRP that accurately evaluates solar's ability to save ratepayers money in the near-term. (Tr. p. 658.) ORS witness Hayet agreed that DESC's pricing of solar was too high and should be improved. (Tr. p. 756.)

Commission Conclusions

The Commission finds that use of demonstrably unrealistic PPA prices in the Proposed IRP require improvement and should be remedied in additional modeling runs. The evidence showed that DESC's PPA cost assumptions were at odds with real world data and overstated the likely cost of PPAs in South Carolina. ORS Witness Hayet agreed that DESC's pricing of solar was too high and should be improved. DESC admitted that use of lower PPA prices would lower the net present value cost of resource plans with the PPA element, but stated the Company was unable to gauge the impact of such reductions without further modeling runs using the updated PPA costs. The Commission finds that the impact of such price reductions should be determined through additional modeling runs of 400 MW solar at three prices in line with indicative South

Carolina pricing: \$34/MWh, \$36/MWh, and \$38.94 /MWh.

Reiterating the earlier point, the Commission finds it reasonable to require DESC, no later than in its 2022 IRP Update, to document how it is or is not prudent to take advantage of the solar ITC or implement a plan to take advantage of the ITC.

2. Battery Storage System Cost Assumptions

Summary of Evidence

Witness Sercy identified problems with the pricing of 100 MW of Company-owned 4-hour duration battery storage that was modeled to come online in 2026. While DESC assumed that storage would have a capital cost of \$1,645/kW, experience in the market shows that estimate is too high. The Santee Cooper RFI—which included indicative prices for adding storage capability to solar PPAs, including two proposals for 4-hour duration batteries—yielded four projects with commercial online dates of 2022 and 2023 at costs of \$1,324/kW and \$1,316/kW, respectively. (Tr. p. 607.19.) These cost figures represent capital costs, financing, and operating costs on a present value basis, while DESC assumed \$1,818/kW and \$1,773/kW for capital costs alone, respectively in 2022 and 2023. (*Id.*) This comparison illustrates that DESC's storage cost assumptions are unreasonably high, thereby inflating the total modeled cost of nine (9) candidate resource plans with battery storage additions, including RP7. (*Id.*) Witness Sercy testified that storage cost assumptions should align with the market prices indicated by the Santee Cooper RFI, and for purposes of modeling a storage PPA recommended using the NREL ATB's medium storage cost case (including capital and fixed O&M 13 costs) with the same 22% ITC safe harbor assumptions discussed above for solar PV. (*Id.*) This adjusted storage pricing model represents the cost of the storage portion of a solar-plus-storage PPA, and would be comparable with (though higher than) market prices based on the Santee Cooper RFI. (*Id.*) Sercy noted that a number of CPRE Tranche 1 winning bids included storage capability, underscoring the economic viability of solar plus storage PPAs. (*Id.*)

DESC Witness Neely in rebuttal testimony agreed that the NREL ATB mid case battery storage cost assumptions are the most reasonable inputs for this technology, with a modification to correctly use nominal dollar values. (Tr. p. 615.15) Witness Sercy responded that the nominal dollar correction pushes the battery PPA model results substantially higher than the prices indicated in the Santee Cooper RFI, and recommended using the ATB low case battery cost assumptions, which, including the nominal dollar correction, are actually more consistent with the Santee Cooper RFI results than the mid case assumptions originally were. (Tr. pp. 615.15 - 615.16) Using these inputs, Mr. Sercy calculated a 2023 battery PPA price of $129.79/kW-year and a 2038 price of $95.28/kW-year. Sercy noted that none of DESC's eight candidate plans includes battery PPAs, underscoring the importance of performing additional modeling to evaluate this resource option. (Tr. p. 615.16) According to Mr. Sercy, a reasonable approach to modeling battery storage PPAs would be to assume a 15-year life, NREL ATB low case nominal capital and O&M costs, no degradation, and after the initial PPA expires, a new 15-year PPA would be added at the capital, O&M, and financing costs for that future year. Mr. Sercy recommend using this approach for purposes of modeling the battery storage PPA included in the RP7-B plan he describes with his recommendations for changes to the 2020 IRP. (Tr.p. 615.16-17.)

Commission Conclusions

The Commission concludes that DESC's storage cost assumptions are unreasonably high, and inflated the total modeled cost of nine (9) candidate resource plans with battery storage additions, including RP7. DESC did not take issue with Mr. Sercy's recommendations for appropriately modeling the cost of storage PPAs. The Commission finds that in modeling the cost of battery storage PPAs in the Modified 2020 IRP, DESC shall use the NREL ATB's low storage cost case (including capital and fixed O&M costs) with the same 22% ITC safe harbor assumptions discussed above for solar PV PPAs. DESC shall also adopt Mr. Sercy's recommended approach to modeling battery storage PPA costs, as described herein.

In its 2022 IRP Update, Dominion shall document how it is or is not prudent to take advantage of the solar ITC or implement a plan to take advantage of the ITC.

3. Battery and Solar Capital Cost Escalation Rates in 2020 IRP Supplement

Summary of the Evidence

The evidence supporting these findings of fact and conclusions is contained in the Company's 2020 Supplemental IRP, testimony of Company Witness Neely, the testimony of Sierra Club Witness Stenclik and the testimony of ORS Witnesses Hayet and Sandonato. ORS Witness Hayet testified that the Company needed to review its assumptions regarding long-term continuing capital cost de-escalation of renewable energy projects since it was unreasonable to assume that solar and battery energy storage system ("BESS") would continue to de-escalate indefinitely. (Tr. pp. 742.12, l. 20 - p. 742.13, l. 2.) This was included in Mr. Sandonato's testimony as Recommendation Item 13. (Tr. p. 729.5.) In response to this recommendation in its Supplemental IRP, the Company used two different escalation rates for battery storage and solar PV, one from 2020 to 2030 and another for 2031 and onwards. (Tr. pp. 297.7, l. 17 - 297.8, l. 9; Table B.) By changing the escalation rates, Witness Neely stated that the cost of battery storage increased over the 40-year planning period. (Tr. p. 297.8, ll. 7-9.)

Sierra Club Witness Stenclik testified on surrebuttal that while he agreed with the Company's decision to use two different escalation rates, the Company implemented it incorrectly in its revenue requirement model which led to overstated battery costs in future years. (Tr. p. 711.4, ll. 10-12.) Witness Stenclik further explained that the de-escalation of the 2031 and later capital costs was based off the capital cost assumptions in the 2020 base year rather than starting from 2030. This resulted in the 2031 and onward capital costs stepping up to a significantly higher level than 2030 and overstating costs in future years. (Tr. pp. 711.4 -711.5; Figures 1-2.)

When asked on cross-examination by Sierra Club about the escalation implementation error, Company Witness Neely stated that it was not an error, that they used an average of the escalation for the last 20 years, under-costing the battery storage in some years and over-costing the battery storage in some years; but that the average is appropriate. (Tr. pp. 402, l. 15 - 403, l. 3.) Witness Neely went on to state that everything related back to the 2020 year, but that the Company has identified this issue as one to improve upon since their existing revenue requirement spreadsheet was designed with only one escalation rate. (Tr. pp. 403, l. 16 - 404, l. 6.)

Commission Conclusions

The IRP is required to include an "analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs." S.C. Code Ann. § 58-37-40(B)(1)(h). While the Company responded to ORS' recommendation to reassess its long-term continuing capital cost de-escalation in its Supplemental IRP, we are persuaded by the testimony of Sierra Club Witness Stenclik that the Company implemented the two different escalation rates incorrectly which led to a spike in capital costs for both solar PV and BESS in 2031 and onwards. The Company is required to correct this error in a Modified 2020 IRP.

4. **ICT Cost Assumptions**

Summary of the Evidence

The evidence supporting these findings of fact and conclusions is contained in the Company's 2020 IRP and IRP Supplement, testimony of Company Witnesses Bell and Neely, testimony of Sierra Club Witness Stenclik and the testimony of ORS Witnesses Hayet and Sandonato.

The Company's 2020 IRP assumed a capital cost for an ICT Frame J of \$469/kW. On rebuttal, Company Witnesses Bell and Neely testified that the \$469/kW was based on a volume discount available to Dominion Energy, Inc. and its subsidiaries. (HE. 1, Ex. EHB-1 p. 42 of 68); (Tr. p. 65.7, ll. 14-18.); (Tr. pp. 297.8, l. 18 - 297.9, l. 4.) Company Witness Neely further testified that Dominion Virginia holds the contract for the volume discount but that he did not know the length of the commitment for the volume discount, but that the Company escalated the price of \$469/kW at 3.75% to the year in which it was installed. (Tr. pp. 399, l. 23 – p. 400, l. 15.)

Sierra Club Witness Stenclik testified that DESC's capital cost assumptions for the ICT was almost 50% lower than other industry sources. Mr. Stenclik's testimony stated that the 2019 NREL Annual Technology Baseline (ATB) overnight capital cost for an ICT is \$899/kW and PJM assumes a capital cost of \$875/kW. (Tr. p. 705.8, ll. 5-10.) In addition, ORS Witness Hayet concluded, as part of ORS's Kennedy Report, that the Company should review its ICT capital cost assumptions for reasonableness since they appear to be low, (Tr. p. 742.13, ll. 2-4) and could potentially bias results in favor of ICT technology. (HE. 20, Ex. AMS-1, p. 61 of 87.) Table 11 of the Kennedy Report indicates a range of ICT capital costs from \$700-\$972/kW from four different sources and points out that Virginia Electric and Power Company (also known as Dominion Virginia) used a capital cost assumption of \$562/kW in its 2020 IRP. (HE. 20, Ex.

AMS-1, p. 60 of 87; Table 11.) When asked on cross examination by the Sierra Club why Dominion Virginia was not using the same volume discount that DESC was quoting, Company Witness Neely did not know. (Tr. p. 399, ll. 7-20.)

Sierra Club Witness Stenclik further stated that the capital cost assumptions for things like the ICT are one of the most critical assumptions in long-term resource planning since it determines which technologies are selected and the cost efficacy of coal retirements. (Tr. p. 705.7, ll. 5-7.) He went on to state that the capital costs for ICTs make up 70% of the total levelized cost of energy, which means that if you make small adjustments to the ICT capital costs, it can drastically alter the competitiveness of the resource. (Tr. p. 705.7, ll. 12-16.) To demonstrate the sensitivity of the capital cost assumptions, Sierra Club Witness Stenclik ran the PLEXOS model using the Company's modeling inputs except he updated both the ICT and the battery storage capital costs to industry standards. Witness Stenclik's model concluded that by making only those two changes, RP8 became the least cost plan at 1.3% lower than RP2. (Tr. pp. 705.15, l. 9 - 705.16, ll. 3; Table 2.)

In addition, Sierra Club Witness Stenclik questioned the appropriateness of using volumetric discounts in long-term planning documents. (Tr. p. 711.7, ll. 10-11.) Witness Stenclik stated that DESC failed to provide the specifics of the vendor quote, what costs were included in the volume discount, how many ICTs would have to be purchased to obtain the volume discount, and if those prices would be guaranteed over the 15-year IRP planning period. (Tr. pp. 711.7 – 711.8.).

Commission Conclusions

The IRP is required to include an "analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs." S.C. Code Ann. § 58-

37-40(B)(1)(h). While the Company provided capital costs for its ICTs, those costs were not reasonable since they were based on a volumetric discount of indeterminate durability or availability. There is insufficient evidence in the record to determine if the volume discount will be available throughout the 15-year planning period, even assuming a 3.75% escalation rate. While the Commission agrees with Company Witness Neely that customers should have the benefit of low-cost generation, there is no evidence in the record to suggest that the $469/kW will be available in 15 years when the Company plans to build its next ICT. For purposes of the IRP, we agree with the recommendation of Sierra Club Witness Stenclik and ORS Witnesses Sandonato and Hayet that the Company should include in a Modified 2020 IRP industry accepted ICT capital cost assumptions, such as NREL. We would also note that the Company relied on data from NREL for determining its future cost of renewable energy projects, so it should do the same for the ICT. (Tr. p. 297.7, ll. 6-8.)

5. Capacity Value Assigned to Solar PV in Modeling

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 9

Summary of the Evidence

The evidence in support of this finding of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

SCSBA Witness Sercy testified that DESC inappropriately assumed that solar PV has zero winter capacity value. Witness Sercy noted that the Commission ruled on this issue in the recent avoided cost proceeding and rejected DESC's assertion that solar PV has zero winter capacity value and instead adopted an 11.8% capacity value for solar PV that recognizes a modest year-round capacity value for incremental solar on the DESC system. Witness Sercy stated that DESC's erroneous assumption of zero capacity value has the effect of increasing the total cost of candidate resource plans that include solar. Witness Sercy recommended that a reasonable assumption for the current IRP is thatsolar PV has a capacity value equivalent to the effective load carrying capacity ("ELCC") specific to the system penetration level of incremental solar PV. Witness Sercy stated that this assumption would be consistent with Order No. 2020-244 but would apply any updates to the amount of solar PV on the system so that the ELCC is representative of the capacity value of incremental solar at this point in time. (Tr. p. 607.18).

DESC Witness Lynch testified that the Commission did not order DESC to assume 11.8% of nameplate solar capacity would be available to serve the winter peak demand and that solar is not able to contribute to winter peaks that occur before sunrise. (Tr. p. 559.24).

SCSBA Witness Sercy stated in surrebuttal testimony that while the Commission did not adopt an assumption that solar PV would provide a high level of capacity value during early morning winter peaks, it recognized that capacity need exists across all hours of the year, such that a resource can have capacity value even if it does not contribute capacity in the absolute highest peak hour. Witness Sercy testified that a utility's capacity need is a function of both load and forced outages at generation and transmission assets. Load is present at all hours of the year, as is the chance of forced outages. This includes all winter season daytime hours, not just winter morning hours, which is why the Commission concluded in its DESC avoided cost order that "ORS witness Horii's recommended 11.8% avoided capacity value is appropriate as it is reflective of the actual avoided capacity value for solar at this time." Witness Sercy also stated that ELCC values are appropriately used both in the context of an avoided cost proceeding and an IRP proceeding. (Tr. pp. 615.17 – 615.18).

Commission Conclusions

The Commission agrees with SCSBA Witness Sercy that, rather than assigning zero capacity value to solar PV resources, it is appropriate for DESC to apply the current ELCC capacity value for solar based on the existing level of operational solar on DESC's system. The Commission notes that it is appropriate to apply the referenced ELCC capacity value to solar PV both in the context of an IRP proceeding as well as an avoided cost proceeding.

In Order No. 2020-244, the Commission ordered DESC to apply an ELCC value of 11.8% based on existing levels of solar on the DESC system at that time. In its Modified 2020 IRP, DESC shall calculate the current ELCC capacity value for solar based on the current level of operational solar on DESC's system, and DESC shall apply that value in its modeling of PV resources.

Prospectively, Dominion shall work with stakeholders regarding fair inclusion of solar PV's winter capacity value in the 2021 and 2022 IRP Updates. This should be a good-faith attempt to reach a mutually agreeable value to propose for assignment for PV capacity value in the winter.

6. Costs of Solar Integration

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 10

Summary of the Evidence

The evidence in support of this finding of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

SCSBA Witness Sercy testified that based on interrogatory responses received from DESC, the Company was applying a methodology for calculating solar integration costs that had previously been rejected by this Commission in another docket – one based on an assumption that solar PV requires DESC to maintain operating reserves equal to 35% of the nameplate capacity of that solar during all generating hours. (Tr. pp. 607.44 – 607.45.) Mr. Sercy concluded that the solar integration costs resulting from this approach resulted in artificially inflated integration cost assumptions for new solar resources within DESC's modeling of resource plans that included solar additions. (*Id.*) Mr. Sercy further recommended that after completion of the Integration Study authorized by Act 62 and currently contemplated in Commission Docket No. 2020-219-A, the results of that Integration Study should be considered in future IRPs.

In their rebuttal testimony, DESC's witnesses did not offer any response to Mr. Sercy's testimony on this point. DESC Witness Neely testified under cross examination that in preparing the Proposed IRP, DESC in fact did not model any additional reserve requirements for uncontracted solar that was added to the system. (Tr. p. 351.) Mr. Neely explained that this was due to constraints within the modeling software and that the Company intends to include in its 2021 IRP an updated methodology for calculating solar integration costs. (Tr. p. 356.) Mr. Neely testified that this new methodology is based on spinning reserve requirements that correlate to the solar generation profile, and results in solar integration costs that are below the $2.29/MWh calculation presented by ORS Witness Brian Horii in the 2019 DESC avoided cost proceeding. (Tr. p. 364.)[9]

Mr. Sercy recommended that, for purposes of conducting a 2021 solar RFP based on additional modeling of near-term solar additions, the ORS-calculated integration charge of $2.29/MWh be adopted. (HE. 13.)

[9] Although Mr. Neely's recollection was that Mr. Horii had recommended an integration charge of $2.39/MWh, the value of Mr. Horii's recommended charge was $2.29/MWh. Order No. 2019-847 at 5.

Commission Conclusions

Act 62 requires that a plan include "an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs." S.C. Code Ann. § 58-37-40(B)(1)(h). This Commission finds that this provision requires that the integration cost of solar additions be considered within the updated modeling to be done by DESC in this proceeding. However, this Commission rejected the methods for calculating the costs of solar integration in its avoided cost docket (Order No. 2019-847, Docket No. 2019-184-E at p.56), and the Integration Study authorized by Act 62 and under consideration in Docket No. 2020-291-A is still pending. As a result, DESC lacks an updated, Commission- approved methodology for calculating integration costs for purposes of IRP modeling.

Commission approved an "interim" integration charge of $0.96/MWh for new uncontrolled solar PPAs in Order No. 2020-244, that is a temporary interim value and is subject to "true-up" (either up or down) based on the results of the Integration Study. Under the circumstances of this IRP, the Commission concludes that consistent with its finding in Order No. 2020-244 at 4, a solar integration cost of $0.96/MWh should be used by DESC when performing the updated resource portfolio modeling required herein, both in the Modified 2020 IRP and in the additional modeling to be produced within thirty (30) days (discussed further below).

Mr. Neely testified that DESC's updated methodology results in solar integration costs that are lower than those previously proposed by ORS, therefore we find that $0.96/MWh is a reasonable assumption that will protect the interest of ratepayers consistent with the requirements of Act 62.

The Commission further notes that because the "new" solar integration methodology described by Mr. Neely (involving the use of spinning reserves) was not included in the Proposed IRP or disclosed to Intervenors in discovery, and because DESC did not provide any evidence or testimony in support of that methodology for review by the Commission, it would be inappropriate for DESC to apply that methodology to any uncontracted solar when conducting additional modeling runs.

E. Scenario Analysis and Selection of the Preferred Plan

1. Consideration of Risk and Use of Risk Metrics

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NOS. 11 & 12

Summary of the Evidence

The evidence in support of this finding of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

DESC Witness Bell testified that the Company determined that environmental risk and associated costs were principally connected to DESC's coal-fired generation units. (Tr. pp. 50.20 - 50.21.) Mr. Bell further notes that each of the Company's resource portfolios represent a distinct approach to environmental compliance and commodity price risk. (Tr. p. 50.28.) He identifies Resource Plan 2 as the most beneficial to customers under "expected conditions," but notes that other resource plans perform better under other sensitivities modeled by the Company. He also notes that because the Company is not facing any decision points in the near term, the eight resource plans in the Proposed IRP represent a range of options that can be pursued in the future. (Tr. p.47 – 48.)

DESC Witness Neely testified that "risk and uncertainties are addressed through the various sensitivities that were modeled along with the variety of resources that made up each of the eight resource plans." (Tr. p. 288.14.)

In its report, ORS determined that commodity price risk was adequately considered in the Proposed IRP through the consideration of natural gas and CO2 price sensitivity cases, and that DESC's "existing resource mix" reflects diversity in fuel source, type, and location. (HE. 20, Ex. AMS-1, p. 22 of 87.)

SCSBA Witness Sercy testified, however, that DESC did not actually utilize any risk assessment methodology in selecting its preferred resource plan, and thus did not comply with the Act 62 factors for identifying the most reasonable and prudent plan. (Tr. p. 607.32.) Mr. Sercy observes that if the bar for balancing the Act 62 factors is simply to *perform* a modeling exercise for multiple candidate plans, then South Carolina ratepayers are "not getting much out of the IRP process." (Tr. p. 615.9.) Mr. Sercy states that Act 62 established a reasonable and prudent standard for IRPs in South Carolina, and the purpose of including concepts like risk and uncertainty in the statute is to actually perform a scenario analysis that can identify the most reasonable and prudent plan in the face of that risk and uncertainty. (Tr. p.615.11.)

Mr. Sercy points out that although DESC claims to select a resource plan reflecting the "most likely scenario," the Company does not provide even a rudimentary explanation of how the Company identified the relative likelihood that any given scenario will unfold. (Tr. p. 607.35.) DESC also failed to consider the results of five out of six scenarios that the Company modeled, including cost results for 40 out of the 48 scenarios. (Tr. p. 607.35)

To address risk associated with picking a resource plan, Lawrence Berkeley National Lab has determined that, "If properly structured, the use of risk-adjusted metrics enables utilities, regulators and other stakeholders to identify investment and procurement strategies that have low costs and are robust across a large number of possible scenarios." (Tr. p. 607.34.) Mr. Sercy identified a number of utilities that use risk-adjusted metrics in IRP, including Dominion Energy

North Carolina. (*Id.*)

For purposes of the 2020 DESC IRP, Mr. Sercy developed cost range and minimax regret analyses that he recommends this Commission adopt for purposes of evaluating and selecting a resource portfolio that meets the requirements of Act 62 by properly balancing both cost and uncertainty across a range of reasonable resource plans and sensitivities. (Tr. p. 607.38.) Mr. Sercy identified cost ranges across natural gas and CO2 price scenarios as an appropriate risk metric for commodity price risk, and regret scores as an appropriate risk metric for diversity of generation supply. To illustrate the use of these risk metrics, Mr. Sercy applied the cost range and minimax regret analysis to DESC's proposed resource portfolios, showing revealed that RP7, and not RP2, outperformed the other portfolios when these metrics were applied. (Tr. pp. 607.37 – 607.39.) Cost range and minimax regret analyses applied to the updated resource portfolios will provide this Commission with the ability to analyze all of the cost modeling results in the DESC IRP, resulting in a systematic and objective methodology for considering the performance of each candidate resource plan under each scenario. (Tr. p. 607.37.) In response to questions from Chairman Williams, Mr. Sercy explained how a low-risk and robust plan that performs well under a broad but reasonable range of possible scenarios better serves ratepayer interests, as compared to the DESC approach of being reactive rather than proactive in the face of risk and uncertainty. (Tr. p. 657.)

In its rebuttal testimony, DESC offered no response to Mr. Sercy's testimony on this issue and did not object to his recommendation that the Company be required to implement risk analysis methodologies. (*See* Tr. p. 380: cross-examination of Mr. Neely, conceding that no one from the Company rebutted Mr. Sercy's recommendations as to how an Act 62 compliant risk analysis could and should be included within the 2020 DESC IRP.) In its IRP Supplement, the

Company did add a new metric to its analysis of resource plans: an average ranking for each of its candidate resource plans, across all modeled scenarios. (Tr. p. 615.26.) However, Mr. Sercy testified on surrebuttal that this was not an appropriate approach to measuring risk, and that using average rankings actually has the effect of hiding risk rather than illuminating it. (Tr. pp. 615.26 - 615.27.)

Commission Conclusions

This Commission finds that DESC did not properly assess risk and uncertainty, as required by Act 62, when analyzing and selecting a preferred resource plan. We also find that comparing risk metric values for candidate resource plans is an appropriate means for considering Act 62 factors such as commodity price risk and diversity of generation supply.

This Commission rejects DESC's approach of selecting a preferred plan based exclusively on a standard of least cost in a "base" or "most likely" scenario, and affirm the approach of selecting a preferred plan based on a balancing of the Act 62 factors, including systematic, quantitative assessment of commodity price risk and diversity of generation supply.

Finally, this Commission finds that the recommendations of Mr. Sercy related to the use of cost range and minimax regret analyses are appropriate for bringing DESC's 2020 into compliance with the requirements of Act 62, and that a stakeholder process is an appropriate venue for further refining the risk-adjusted metrics that DESC should apply to future IRPs. The Commission will require DESC to implement the cost range and minimax regret analyses in the Modified 2020 IRP and subsequent updates and will consider more refined and sophisticated risk-adjusted metrics in its 2022 IRP Update.

2. Sensitivity Analyses

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 13

Summary of the Evidence

The evidence in support of this finding of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

DESC witness Bell stated in his direct testimony that the cost modeling in the Proposed IRP includes assessments of the sensitivity of the proposed resource plans to key variables such as natural gas prices, costs imposed on carbon dioxide ("CO2") emissions, and variations to load impact through DESC's investment in DSM programming. In all, the IRP models the results for customers against eight resource plans and 64 distinct scenarios. (Tr. pp. 50.4, 50.14, 50.20 - 50.21, 50.24 - 50.26). DESC Witness Bell provided an overview of the effect of these sensitivities on the costs of the candidate resource plans. (Tr. V pp. 288.17 - 288.19).

SCSBA witness Kenneth Sercy testified to the importance of properly-designed sensitivity analyses in integrated resource planning. If scenarios and sensitivities are poorly designed, then IRP modeling results will not be representative of the possible futures that may unfold, creating a danger of selecting a resource plan that does not align with decision-maker cost and risk preferences, leading to bad outcomes for customers. (Tr. pp. 607.23 - 607.24.) According to Mr. Sercy, best practices for designing "reasonable" scenarios includes "Construct[ing] a range of plausible, internally consistent scenarios that characterize the range of uncertainty," with an emphasis on "explicit consideration of the wide range of uncertainty" facing the electric industry. *Id.*

Mr. Sercy testified that he had three principal concerns with the sensitivity analyses in the Proposed IRP: (1) candidate resource plans were not tested for cost impacts of load diverging from the base forecast, and the range of load forecasts developed is overly narrow; (2) DESC's gas price sensitivity assumptions are skewed low; and (3) the range of DESC's CO2 sensitivity assumptions is overly narrow. According to Mr. Sercy, each of these issues skews the cost results, creating a misleading dataset for selecting the preferred plan. (Tr. p. 607.25.)

Load forecasts

With respect to load conditions, Mr. Sercy opined that the range of the load forecasts is too narrow and thus does not represent a "wide but plausible" set of potential future load conditions. Mr. Sercy observes that the CRA report draws a similar conclusion, noting that "future IRPs could be enhanced by considering lower probability load outcomes that range further from the Base case outlook." (Tr. p. 609.25 citing CRA Report at 39.) Second, DESC doesn't actually *use* its load forecast sensitivities in its cost modeling analysis, and thus provides no information about how different resource plans are able to adapt to diverse load conditions. (Tr. p. 609.25.) Mr. Sercy recommends that DESC's IRPs should quantitatively assess how different resource plans perform when load conditions shift, so that this information can be considered when selecting a reasonable and prudent plan. (Tr. pp. 607.26 - 607.27.) Finally, Mr. Sercy notes that resources that can be economically procured in smaller increments and that have shorter procurement lead times, such as solar PV and DSM, are well-suited to enhancing the adaptability of a resource plan to load forecast shifts. *Id.*

DESC Witness Bell states in his rebuttal testimony that DESC "intends to work with ORS and other interested parties" to "Expand the number of sensitivities the IRP analyzes to include both DSM scenarios and a range of load growth sensitivity factors as appropriate" in future IRPs. (Tr. Vp. 65.18.) DESC Witness Lynch also states that the Company will consider providing a wider range of load forecasts in the future, and explains that DESC did not actually model load forecasts in the 2020 IRP economic analysis, other than the base forecast, because the Company believed it would "produce too many scenarios making it unreasonably difficult to draw meaningful conclusions from the study." (Tr. p. 559.10.)

Natural gas prices

With respect to natural gas prices, Mr. Sercy testified that DESC's natural gas price sensitivities are skewed towards lower pricing assumptions, and do not represent a "wide but plausible" set of potential gas prices. (Tr. pp. 607.26 - 607.29.) According to Mr. Sercy, DESC's approach to forecasting natural gas prices was unreliable, in that it relied on a "simple, and in some cases arbitrary, compound annual growth rate assumptions applied to current prices," rather than detailed supply and demand modeling. Mr. Sercy illustrated to low bias of DESC's natural gas projections in comparison to forecasts included in the Department of Energy's 2019 Annual Energy Outlook ("AEO"). *(Id.* 607.28.) On average, the AEO prices are 19% higher than DESC's in the base case, 14% higher in the high case, and 23% higher in the low case. These price differences have very large impacts on production costs and overall candidate resource plan cost results across the scenarios, with lower gas price assumptions favoring gas-fired resources.

In his rebuttal testimony, DESC Witness Bell stated that the Company would "Reexamine its natural gas forecasts and their relationship to other industry forecasts while expanding the range of forecast sensitivities to provide more variation in range from the base or expected price curve." (Tr. p. 65.19.) DESC Witness Neely directly addresses Mr. Sercy's critique of the company's gas price projections, although his only response is that since Mr. Sercy filed his direct testimony, the Energy Information Administration's AEO 2020 report is now available, and that its reference case includes natural gas price projections that are closer to DESC's base case projections than are the AEO 2019 reference case projections advocated by Mr. Sercy in his direct testimony. (Tr.

pp. 297.29 - 297.30.) Mr. Neely claims that the Company's approach to forecasting gas prices is "not unreasonable," but offers no support for that proposition. *Id.*

On surrebuttal, SCSBA witness Sercy pointed out DESC's failure to respond to his substantive critiques, and further explained why DESC's approach of calculating year-by- year escalation rates from AEO price projections and then applying those rates to an initial NYMEX price is not an appropriate methodology for forecasting long-term prices. Such an approach has the result that transient short-term market dynamics, such as gas storage inventories and recent weather patterns, become reflected in long-term prices. AEO forecasts, by contrast, represent complex long-term market interactions to project prices. Changing long-term market dynamics are captured as various data and structural shifts are incorporated into the AEO as part of its annual release schedule. (Tr. pp. 615.23 - 615.24.)

Carbon prices

With respect to carbon pricing, Mr. Sercy also opined that DESC had failed to model "a wide but plausible set of potential CO_2 prices" in the Proposed IRP. (Tr. pp. 607.29 - 607.30.) DESC modeled only two potential CO_2 prices in its sensitivity analyses: \$0/ton and \$25/ton of CO_2 emissions. Mr. Sercy testified that DESC's "high" CO_2 price was substantially lower than even the lowest non-zero CO_2 price projected in AEO 2019.

Mr. Sercy recommended that DESC be required to re-run the 2020 IRP modeling using the AEO low, reference, and high gas prices described in his testimony, and using the AEO high CO_2 case. (Tr. P. 607.31) For future IRPs and updates, Mr. Sercy recommended that DESC be required to: (1) develop a wide but plausible range of load forecasts, and ensure that cost modeling captures each resource plan's capabilities to adapt to load that diverges from the base forecast; (2) use a wide but plausible range of gas price projections from AEO or another public, credible fundamental gas supply-demand model; and (3) use wide but plausible zero/medium/high CO_2 cost projections from AEO or other public sources. (Tr. p. 607.31.)

ORS's report on DESC's Proposed IRP concurred with Mr. Sercy's assessment of DESC's natural gas price projections, concluding after a comparison of DESC's gas price projections to other utility and industry forecasts that "DESC gas price forecasts are lower than the comparative forecasts, including the consensus forecast in all three (3) gas price cases." (HE. 20, Ex AMS-1, "ORS Report" at p. 51 of 87.) ORS also criticizes DESC's gas forecasting methodology, stating that "ORS is concerned that the Company's escalation methodology may understate gas prices beyond the initial three year forecast in the low and base gas price sensitivities." *Id.* Notwithstanding these critiques, ORS recommends only that DESC revisit its approach to modeling gas prices in future IRPs, rather than address the issue now.

In his rebuttal testimony, DESC witness Bell stated that the Company would "include additional CO_2 price sensitivities in future IRP scenarios based on appropriate forecasts." (Tr. p. 65.19.) DESC did not otherwise respond to Mr. Sercy's critiques regarding its CO_2 price sensitivity analysis, and did not oppose or otherwise respond to Mr. Sercy's recommendation that it be required to use the AEO high CO_2 case to capture a reasonable range of greenhouse gas policy outcomes. (*See* Tr. at p. 615.4-5 (Sercy Surrebuttal, summarizing SCSBA recommendations not responded to by DESC).)

<u>Commission Conclusions</u>

Act 62 requires each utility's IRP to include and consider sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks. S.C. Code Ann. § 58-37-40(B)(1)(e)(ii). In addition, the IRP must analyze, for each proposed generation resource, "fuel cost sensitivities under various reasonable scenarios." *Id.* § 58- 37-40(b)(1)(b). As previously discussed, these requirements are consistent with Act 62's overall emphasis, discussed above, on identifying and protecting ratepayers from risk. As Mr. Sercy testified, poorly designed cost and sensitivity analyses can create skewed cost results that mislead decision-makers about which plan is most prudent. (Tr. p 607.7.) And indeed, the Commission concludes that the identified problems with DESC's forecasting of natural gas prices, CO_2 pricing, and future load collectively make the results of its current production cost modeling (including that in the IRP Supplement) unreliable.

Load forecasts

The Commission finds persuasive the critiques of DESC's approach to load forecast sensitivities advanced by SCSBA witness Sercy. DESC appears to acknowledge that is an area where its approach to devising its IRP can be improved, but that this is not a fix than can be implemented in time for the Modified 2020 IRP. Therefore, the Commission will require DESC, in its 2022 IRP, to work with stakeholders to develop a wide but plausible range of load forecasts, and ensure that cost modeling captures each resource plan's capabilities to adapt to load that diverges from the base forecast.

Natural gas prices

Natural gas price assumptions are key data inputs within the IRP modeling, exerting a powerful influence on system operations and total revenue requirements for each plan. (Tr. p. 615.25.) And although there is merit to ORS's suggestion that DESC conduct a long-term inquiry into its methods for preparing gas price forecasts, given the ready availability of industry-standard, consensus gas price forecasts, there is no reason not to direct DESC to correct these deficiencies sooner rather than later. The Commission finds persuasive the testimony of Mr. Sercy that in projecting natural gas prices, it is far more inappropriate to rely on industry-standard market models than on escalation rates from current data points. The Commission will therefore direct DESC, in the production cost modeling conducted for the Modified 2020 IRP, to use the AEO low, reference, and high gas prices described by Mr. Sercy in place of DESC's low, base, and high gas prices,

Carbon prices

The Commission finds Mr. Sercy's testimony regarding the "wide but plausible" range of possible future CO_2 prices persuasive. DESC also appears to have conceded that it is appropriate for it to include a broader range of CO_2 price forecasts in its IRP. The Commission appreciates the Company's commitment to doing so in future IRPs, but concludes that it would also be appropriate, and not unduly burdensome, to require the Company to include a broader range of CO_2 price forecasts in its Modified 2020 IRP. The Commission will therefore direct DESC, in its Modified 2020 IRP and future updates, to use the AEO high CO_2 case described by Mr. Sercy in place of DESC's $25 CO2 case, in the revised cost analysis.

Since the Company's exposure to carbon pricing is inextricably linked with its use of coal generation, The Commission finds it appropriate for the Company to target the 2023 IRP to begin showing coal retirement as another option upon the completion of their coal retirement study. Even without the benefit of a completed coal retirement study, The Commission finds that it is prudent for Dominion to add at least one additional lower carbon option to the 2021 or 2022 IRP Update for modeling incorporating additional solar and storage opportunities.

3. Evaluation of Demand-Side Resources

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NOS. 14- 16

Summary of the Evidence

The evidence in support of this finding of fact is found in the Proposed IRP and IRP

Supplement, testimony and exhibits of DESC witnesses Eric Bell and Therese Griffin, testimony and exhibits of SACE/CCL witness David Hill, and testimony of ORS witness Phillip Hayet.

SACE/CCL Witness Hill testified that DESC did not fully and accurately characterize and include DSM resources in its proposed IRP. Specifically, Witness Hill testified that DESC did not include a fair evaluation of a High DSM case as required by Act 62. DESC presented a High DSM case with a level of savings equal to 1% of annual retail sales, but dismissed the High DSM case on the grounds that it was not supported by the Company's 2019 Market Potential Study ("2019 MPS") and was "based only on estimates, likely not achievable and cost effectiveness is unknown." (HE. 1 (Ex. EHB-1), p.42.) Witness Hill testified that this dismissal was unreasonable because the 2019 MPS only evaluated the Medium DSM case and did not include analysis of DSM portfolios with higher levels of savings. (Tr. p. 681.26, ll. 1-17.) Witness Hill testified that the Company's failure to include an evaluation of the high DSM case was particularly concerning because DESC's modeling showed for most of its portfolios, the net present value of levelized costs for the high DSM case were lower compared with the medium DSM case. (Tr. p. 681.26, ll. 1-17.)

Witness Hill further testified that the DSM analysis in the proposed IRP was deficient due to its failure to evaluate a High DSM case with savings levels exceeding 1%, citing examples from other public and investor-owned utilities that have been able to meet those savings levels (Tr. pp. 681.20, l. 17 – 681.21, l. 8.), overstated the costs of DSM while understating its benefits (Tr. pp. 681.24, l. 9 – 681.25, l. 9.), and unreasonably assumed that DSM savings would not increase for the 30 years after 2029. (Tr. p. 681.25, ll. 10-21.) Witness Hill ultimately recommended that the Commission reject the proposed IRP.

DESC Witness Therese Griffin responded to Witness Hill by stating that a 1% level of savings was not supported by the 2019 MPS. (Tr. pp. 225.2, l. 21 - 225.3, l. 5.) Witness Griffin further stated that the 2019 MPS was already litigated in Docket No. 2019-239-E, and that many of Witness Hill's critiques were raised in that proceeding but ultimately rejected by the Commission in Order No. 2019-880. (Tr. p. 219, ll. 15-20.) Witness Hill responded by stating that the 2019 MPS did not evaluate the cost-effectiveness or achievability of savings levels beyond the medium DSM case, rendering DESC's statement that the cost-effectiveness of the high DSM case was unknown "a foregone conclusion." (Tr. p. 686.5, ll. 1-9.) Witness Hill further testified that he did not seek to relitigate the 2019 MPS, but rather to evaluate whether DESC's IRP satisfied the requirements of Act 62, which were not applicable to the Commission's decision in Docket 2019-239-E. (Tr. pp. 686.6, l. 12 - 686.7, l. 13.)

Witness Griffin testified at the hearing that the 2019 MPS did not include any evaluation of the cost effectiveness or achievability of savings levels over and above 0.7%, the level of savings expected from DESC's expanded EE portfolio. (Tr. pp. 243, l. 8 – 244, l. 18.) Witness Hill, at the request of Commissioner Ervin, prepared a Late-Filed Exhibit outlining a DSM Action Plan the Company could take to implement his recommendations in a Modified IRP and future IRPs. (HE. 16.)

ORS Witness Phillip Hayet also testified regarding DESC's failure to support or analyze its High DSM case assumptions in the proposed IRP, noting that it is "highly unusual for a utility to distance itself from its own IRP assumptions as DESC has." (Tr. p.742.10, ll. 20-21.) Witness Hayet testified on surrebuttal that he was ultimately satisfied with DESC's analysis because the Company stated it would conduct a full analysis of all its DSM assumptions in future IRPs. (Tr. pp. 748.15, l. 15 – 748.17, l. 11.)

Commission Conclusions

After considering the evidence of record on this issue, the Commission concludes that proposed IRP did not include a fair evaluation of a High DSM case, as required by S.C. Code Ann. § 58-37-40(B)(1)(e)(Supp. 2019). S.C. Code Ann. § 58-37-40(B)(1)(e) requires thatan IRP include an evaluation of a low, medium, and high DSM case, developed "with the purpose of *fairly* evaluating the range of demand- and supply-side resources available to meet the utility's service obligations." S.C. Code Ann. § 58-37-40(B)(1)(e)(Supp. 2019) (emphasis added).

As an initial matter, we reject DESC's assertion that it need not conduct a comprehensive evaluation of the High DSM case in its IRP because of the Commission's Order approving the Company's expanded DSM portfolio in Docket No. 2019-239-E. That proceeding was not subject to the requirements of Act 62 and the Commission's approval of the Company's DSM portfolio does not relieve DESC of its separate statutory duty to comply with the IRP provisions of Act 62. We find that a "fair evaluation" of DSM resources under Act 62 requires a utility to evaluate the cost-effectiveness and achievability of a range of savings levels and based on such evaluation, make a reasonable determination of savings levels for the Low, Medium, and High DSM cases. DESC has not demonstrated that it conducted any such evaluation with respect to the High DSM case presented in its IRP or that its selection of a 1% savings level for the High DSM case was reasonable.

As DESC Witness Griffin confirmed, the 2019 MPS merely established that 0.7% savings, the Medium DSM case, was cost-effective and achievable in DESC's territory; it did *not* evaluate incremental savings levels over and above that amount. (Tr. p. 243, ll 8-15.) Nor did DESC conduct a separate evaluation of the High DSM case in its proposed IRP. As such, DESC's dismissal of the High DSM case as "likely not cost effective or achievable" is not supported by the 2019 MPS or any other evaluation, and does not constitute a fair evaluation of a high DSM case as required by Act 62.

Finally, we find DESC's decision not to evaluate a high DSM case with greater than 1% savings to be unreasonable and without support. As SACE/CCL Witness David Hill provided in his testimony, utilities across the country have achieved savings levels exceeding 1%. DESC has not conducted any analysis showing that these higher savings levels are not achievable in its territory. As Witnesses Hill and Hayet noted in their testimony, the fact that the High DSM case was least-cost for most scenarios modeled should have prompted DESC to *further* evaluate the High DSM case, not to dismiss those results out of hand. (Tr. pp. 678, l. 11- 679, l. 1; pp. 681.19-681.26; p. 681.36, ll. 10-20; pp. 682-685; pp. 686.1-681.10; pp. 742.10, l. 12- 742.11, l. 17; p. 748.8; pp. 748.14, l. 21 – 748.17, l. 11.)

The fact that DESC did not include a fair evaluation of the High DSM case renders the proposed IRP insufficient under Act 62; though the Company promised to evaluate all its DSM assumptions in future IRPs, its 2020 IRP is nevertheless deficient. However, the Commission does recognize that DESC will require some time to conduct a full evaluation of the cost-effectiveness and achievability of savings levels meeting and exceeding 1%. The Commission finds that the DSM Action Plan outlined in the Late-Filed Exhibit of SACE/CCL Witness Hill represents a reasonable and practical approach and adopts those recommendations with some modifications as outlined below.

The Commission adopts the recommendation in Step 1 of Witness Hill's Late-Filed Exhibit, which directs DESC to conduct a "rapid assessment" of the cost-effectiveness and achievability of ramping up its current portfolio to achieve at least a 1% level of savings in the years 2022, 2023, and 2024. (HE. 16, p. 3 of 7.) As outlined in step 1 of that exhibit, DESC must work with the Advisory Group in conducting this "rapid assessment" and must include the results of this "rapid assessment" in its Modified 2020 IRP. *Id.* The Modified 2020 IRP must also include steps the Company will take to complete the "comprehensive evaluation" discussed below in preparation for including such an evaluation in its 2022 IRP. *Id.*

The Commission declines to adopt Step 2 of Witness Hill's Late-Filed Exhibit, as the Commission is requiring DESC to conduct other modeling in its IRP revisions that may conflict with this step or substantially increase the time DESC would need to complete it. (HE 16, p. 4 of 7.) Rather, the Commission finds that DESC will be required to evaluate these higher levels of savings as part of the "comprehensive evaluation" discussed below.

The Commission adopts Steps 3 through 5 as discussed in Witness Hill's Late-Filed Exhibit, and DESC is directed to include this comprehensive evaluation in its 2023 IRP. (HE. 16, pp. 4-5 of 7. In its 2023 IRP, DESC must include a comprehensive evaluation of the cost-effectiveness and achievability of higher levels of savings, including savings levels of 1.25%, 1.5%, 1.75% and 2%. As outlined in step 3 of the late-filed exhibit, this comprehensive evaluation must consider substantive additions and modifications to the Company's existing DSM portfolio. *Id.* at 3. In implementing this plan, DESC must work with stakeholders, particularly the Advisory Group, and provide opportunities for iterative review, input, and feedback on the Company's analysis and subsequent portfolio development. As part of this presentation in the 2023 IRP, DESC shall include potential incentive options and best practices to achieve the modeled levels of DSM.

4. Balancing of Act 62 Factors

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NOS. 17- 22

Summary of the Evidence

The evidence in support of this finding of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

Many of our findings above are relevant to the balancing factors outlined in S.C. Code Ann. § 58-37-40(C)(2)(Supp. 2019); this section summarizes testimony regarding these factors that is not already captured above, particularly testimony regarding additional information needed for the Commission to balance these factors and whether the Commission should accept the conclusion of the Charles River Associates Review (the "CRA Review") as to the overall reasonableness of the proposed IRP.

a. Sufficiency of Information Related to § 58-37-40(C)(2) Balancing Factors

SACE/CCL Witness Sommer also provided testimony on information not included in DESC's proposed IRP that would be necessary or helpful to the Commission in balancing the seven factors outlined in S.C. Code Ann. § 58-37-40(C)(2).

On the first balancing factor, "resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins," Witness Sommer testified that she had never reviewed another IRP using the "base" or "peaking" reserve margin as used in the proposed IRP. (Tr. p. 476.17, ll. 13-14.) She recommended that the Commission reject an IRP based on resource adequacy standards that are not industry standard or thoroughly vetted by the Commission or intervenors. (Tr. p. 476.17, ll. 9-12.)

As to the second balancing factor, "customer affordability and least cost," Witness

Sommer recommended that the Commission require that DESC calculate the rate and bill impacts of its various portfolios in the IRP, rather than just a levelized NPV of revenue requirements. (Tr. p. 476.17, l. 17 – p. 476.18, l. 15.)

For the third factor, "compliance with applicable state and environmental regulations," Witness Sommer testified that IRPs typically include evaluations of unit compliance with state environmental regulations, along with the Coal Combustion Residuals rule, the Steam Electric Power Generating Effluent Guidelines and Standards, National Ambient Air Quality Standards, and current and potential future greenhouse gas-related rules. (Tr. p. 476.18, ll. 16-21.) Witness Sommer provided an excerpt from Xcel Energy's IRP as one example of such a discussion in another utility IRP. (Tr. p. 476.18, ll. 21-22; HE. 6) Witness Sommer testified that the DESC proposed IRP included only a "cursory" discussion of environmental rules and lacked any meaningful analysis or consideration of how state or federal environmental regulations might affect DESC's generating units or resource choices. (Tr. p. 476.18, l. 22 – p. 476.19, l. 2.)

On "power supply reliability," Witness Sommer noted that the proposed IRP lacked data regarding the performance of its generating units, and recommended that DESC be required to include such data in its IRP. (Tr. p. 476.19, ll. 3-15.) Witness Sommer testified that such data could include several years of recent generator performance data in its IRP, as well as data reported to the North American Electric Reliability Corporation, such as generating unit equivalent availability factor, forced outage rate, and other metrics. (*Id.*) Witness Sommer also testified that it would also be useful to develop a requirement for reporting of individual events like hurricane-related outages, such as the location of outages, length of outages, or repairs needed to bring customers back online. (*Id.*)[10]

DESC Witness James Neely responded only to Witness Sommer's argument as to the need to include recent generator performance data in the IRP filing. (Tr. pp. 297.32, l. 17 – 297.33, l. 5.) Witness Neely testified that such information was not a logical part of an IRP filing and that such information was available in DESC's annual fuel cost proceedings and, with respect to storms, allowable *ex parte* briefings DESC makes to the Commission. (Tr. p. 297.33, ll. 1-5.) Witness Sommer provided surrebuttal testimony noting that interested parties may not be aware of where to find this information in other proceedings, and that to ensure transparency an IRP should, to the extent possible, function as a standalone document. (Tr. pp. 479.7, l. 11 – 479.8, l. 9). Witness Sommer also noted that Witness Neely did not specify what alternative information the IRP provided that the Commission could use to evaluate whether the plan appropriately balanced "power supply reliability." (*Id.*) On cross- examination, Witness Neely testified that neither the Company's previous filings in fuel dockets nor its prior allowable *ex parte* briefings were part of the record in this proceeding. (Tr. p. 304, ll. 4-8).

b. Charles River Associates Review of the Proposed IRP

DESC Witness Eric Bell included as an exhibit to his direct testimony a report by Charles River Associates ("CRA") in which CRA reviewed and commented on the reasonableness of the proposed IRP (the "CRA Review"). The CRA Review found overall that the approaches and methodologies used in the proposed IRP were reasonable. (HE. 2, Ex. EHB-2, p. 9-11).

SCSBA Witness Kenneth Sercy testified that the CRA Report did not constitute an independent third-party assessment of the proposed IRP. (Tr. pp. 607.8, l. 14 – 607.9, l. 8.)

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[10] Witness Sommer also testified as to whether the proposed IRP appropriately considered commodity price risk and diversity of generation supply. (Tr. pp. 476.19, l. 16 - 476.20, l. 17.) We believe our holdings in section XX of this Order adequately address these two factors.

Witness Sercy noted that CRA was selected by ORS and DESC in conjunction with a settlement from the merger proceeding, and hired by DESC to prepare the CRA Review for this proceeding. Witness Sercy contrasted this with a Power Advisory report the Commission relied on in DESC's recent avoided cost filings, as Power Advisory was neither selected nor paid by any utility. (*Id.* at p. 607.9, ll., 1-8)

SACE/CCL Witness Anna Sommer testified that she disagreed with the CRA Review's conclusion as to reasonableness of DESC's proposed IRP. (Tr. p. 476.20, ll. 22-23.) Witness Sommer noted that she has familiarity with CRA's previous work, and generally believed that CRA held DESC to an unreasonably low bar in reviewing the proposed IRP. (Tr. p. 476.20, l. 23-24; pp. 476.20, l. 19 - 476.23, l. 2.) She also testified that the CRA Review did not sufficiently evaluate whether the proposed IRP contained sufficient information about DESC's methodologies and assumptions, noting that in several instances, the CRA Review was more descriptive than the proposed IRP itself, and that CRA appeared to have to collect significant additional information to complete its assessment. (Tr. pp. 476.23, l. 3 – 476.24, l. 12.) Witness Sommer also testified that the CRA Review was insufficient for its failure to determine whether the proposed IRP satisfied the requirements of Act 62. (Tr. p. 476.24, ll. 10-12.)

Commission Conclusions

The Commission agrees with Witness Sommer that the proposed IRP does not provide sufficient information with regard to several of the balancing factors outlined in S.C. Code Ann. § 58-37-40(C)(1) (Supp. 2019). The Commission is directed to make a finding as to whether the IRP represents the *most* reasonable and prudent plan, which requires that there is sufficient information in the record for this proceeding to make such a finding. The Commission does not believe that Witness Sommer's recommendations are unduly burdensome to DESC; indeed, her testimony shows that other utilities routinely include such information in IRP filings.

For that reason, the Commission adopts Witness Sommer's recommendation that DESC be required to calculate the rate and bill impacts of its various portfolios in the IRP, rather than just a levelized NPV of revenue requirements. DESC must include such an evaluation in its Modified 2020 IRP and in future IRPs and IRP Updates.

The Commission also agrees that the proposed IRP does not include sufficient information regarding compliance with applicable state and environmental regulations. DESC is directed to revise its 2020 IRP to include further analysis and consideration for how state or federal environmental regulations, including the Coal Combustion Residuals rule, the Steam Electric Power Generating Effluent Guidelines and Standards, National Ambient Air Quality Standards, and current and potential future greenhouse gas-related rules, might affect DESC's generating units and resource choices.

The Commission also adopts Witness Sommer's recommendation that DESC be required to include several years of recent generator performance data in its IRP, along with generating unit equivalent availability factor, forced outage rate, and other data that DESC reports to the North American Electric Reliability Corporation. DESC shall also be required to include in its IRP reporting of storm and hurricane-related outages, including the location of outages, length of outages, and repairs needed to bring customers back online. The Commission finds that such information, which could be used to identify vulnerabilities in DESC system, is relevant and necessary to the Commission's evaluation of whether this and future DESC IRPs adequately account for power supply reliability.

Due to the deficiencies identified in all of the Commission findings above, the Commission rejects the conclusion of the CRA Review and finds that, at the time of this review, the proposed IRP does not constitute the most reasonable and prudent plan to meet DESC's energy and capacity needs.

F. Competitive Procurement of Renewable Resources

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NOS. 23- 24

Summary of the Evidence

The evidence in support of this finding of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

There was substantial discussion of the potential for competitive procurement of renewable resources in the evidence and testimony put forth by the parties. In his direct testimony, SCSBA Witness Sercy testified that the procurement of solar and/or storage prior to 2026 could result in significant cost savings for ratepayers, given the ability of developers to take advantage of the 22% ITC for projects that go in-service by 2023. Mr. Sercy noted that a recent procurement conducted by Duke Energy in North and South Carolina allowed Duke to procure long-term solar additions at prices far lower than the solar PPA prices modeled by DESC – an average of $38/MWh for winning bids in Tranche 1 of Duke's Competitive Procurement of Renewable Energy ("CPRE") program, as compared to DESC's assumed cost of $47.77/MWh for a comparable solar PPA. And a 2019 request for information ("RFI") issued by Santee Cooper found a weighted average levelized cost of less than $28/MWh for 20-year solar PPAs. The General Assembly subsequently authorized Santee Cooper to move forward with the procurement of up to 500 MW of solar PV based on the RFI results. (Tr. pp. 607.16, 1.12 – 607.17, l. 4.) As previously noted, Mr. Sercy testified that the Commission would likely need to take steps soon to in order to complete a procurement in time for bidders to take advantage of the ITC.

DESC did not respond to Mr. Sercy's testimony regarding solar procurement in the rebuttal testimony of its witnesses, and did not dispute that competitive procurement can create opportunities for cost-savings for ratepayers.

Mr. Sercy testified on surrebuttal that modeling conducted in this proceeding could be used to assess the potential benefits to ratepayers of a solicitation. For example, modeling solar PPAs with several price sensitivities could be used to estimate the price point at which solar PPAs would be part of the most reasonable and prudent resource plan. He recommended that DESC be required to model a set of PPA price sensitivities, which could in turn be used to inform the design parameters for a competitive procurement. (Tr. pp. 615.38, l. 7 – 615.39, l. 11.) Mr. Sercy recommended that solar PPAs be modeled at the generic $38.94/MWh price point, as well as $36/MWh and $34/MWh. (*Id.* at Tr. p. 615.39, ll. 10-11.)

At the hearing, DESC Witness Neely testified that he was unfamiliar with Duke's CPRE program, and that did not look into the PPA prices obtained by Duke in that program, even after reviewing Mr. Sercy's testimony about the CPRE program. (Tr. pp. 325, l. 17 – 328, l. 16.) And DESC Witness Bell testified that in modeling solar PPA costs for its IRP, it had not considered whether conducting a competitive solicitation or RFP would allow the company to procure solar energy at costs lower than its assumed PPA costs (discussed infra). (Tr. p. 95, ll. 1-23.)

But Mr. Neely agreed that a competitive solicitation would be "a good way" for the company to test whether developers could deliver solar PPAs at prices that would result in savings to ratepayers. (Tr. p. 329, ll. 9-14; p. 385.)

Mr. Bell acknowledged that if the Company could, through an RFP, contract at lower rates than those modeled in the IRP, it could pass those cost savings on to ratepayers. (Tr. p. 95, ll. 17-21.) And Mr. Neely testified that if the Company were to conduct an RFP, it could set maximum pricing to ensure that any resources contracted through the IRP were "a good deal" for ratepayers. (Tr. pp. 385, l. 21 – 386, l. 3.)

Mr. Sercy testified at the hearing that if a solicitation were conducted, PPAs would likely have to be awarded by the third quarter of 2021 to capture the value of the 22% ITC. (Tr. p. 624, l. 21 – 625, l. 23.) Mr. Sercy confirmed Mr. Neely's assessment that in establishing an RFP, the Commission could establish "cost boundaries" to ensure that resources procured through an RFP would cost no more (and perhaps less) than the cost assumptions in the IRP. (*Id.* at pp. 626-628.) This would protect ratepayers from excess costs and create opportunities for further savings. ORS Witness Philip Hayet, in testimony at the hearing, agreed that if an RFP could be accomplished by the third quarter of 2021 ("Q3"), it would be reasonable to pursue that. (Tr. pp. 758, l. 20 – 759, l. 23.)

At the Commission's request, the SCSBA provided a late-filed exhibit setting forth a potential action plan for executing a competitive procurement that would award contracts in Q3 2021. SCSBA proposed as a first step that the Commission require DESC to conduct additional modeling runs that include near-term solar plus storage procurements, using updated inputs (consistent with the requirements in this Order regarding modeling assumptions and methodologies) for those modeling runs. (HE. 13.) DESC filed a responsive exhibit, which opposed any procurement plan on the following grounds: (1) there is no need for additional capacity or energy on DESC's system; (2) there is no cost benefit from a procurement (3) the structure of SBA's proposed procurement is "fundamentally flawed" because it would only call for the procurement of solar resources, rather than an all-source solicitation; (4) an RFP would "limit future options" for other technologies like wind and nuclear generation; and (5) SCSBA's proposal is beyond the Commission's power to order in an RFP proceeding. (HE. 14.) DESC also argues that Act 62 only authorizes the Commission to open generic dockets relating to competitive procurement, and does not authorize the commission to create "a ***specific*** docket to require the ***specific*** procurement of a ***specific*** block of power[.] "(*Id.* (emphasis in original).)

Commission Conclusions

The parties provided ample testimony that solicitation of solar and/or storage resources via a competitive solicitation ***has the potential*** to create opportunities for ratepayer savings, by allowing the utility to procure energy from such resources more cheaply than it can generate it. The opportunities for such savings are greatest for an RFP that concludes by Q3 2021, so that participants can potentially take advantage of the 22% ITC. This is ambitious timeline but a potentially achievable one, and it is in the interest of ratepayers to try. Although all-source competitive procurements (as DESC proposes in HE 14) might eventually prove to be the best option for procuring new resources, Act 62 specifically authorizes this Commission to consider "creating programs for the competitive procurement of energy and capacity ***from renewable energy facilities,***" S.C. Code Ann. § 58-41-10(E)(2), and the Commission has already opened a docket to consider whether such programs would be in the public interest. In any event, there is no evidence to suggest that an all-source procurement could be devised and achieved on this timeline.

Additional modeling can determine the price threshold at which ratepayer savings will occur. And an RFP can be structured to limit the aggregate cost of the procurement so that ratepayer costs will not exceed that threshold. This will ensure that an RFP does not impose excess costs on ratepayers, whether or not the utility has a need for additional capacity. Although DESC is correct that full implementation of a resource procurement is outside the authorized scope of this IRP docket under Act 62, the Commission certainly has discretion in this docket to require the Company to conduct additional modeling and cost analysis (of the same kind and scope as the Company is performing for its IRP) that may inform the Commission and the parties in the competitive procurement docket. The Commission rejects as nonsensical DESC's argument that Act 62 authorizes only the creation of a generic procurement docket, given that the statute specifically authorizes the creation of procurement programs within each utility's balancing authority area "if the commission determines such action to be in the public interest."

Accordingly, the Commission will direct DESC to conduct additional production cost modeling and analysis, as recommended by SCSBA, on an expedited basis (within 30 days of this Order) in order to inform decisions regarding the possible conduct of near-term competitive solicitations. This modeling shall include the RP2 resource plan (as modified using the same input and methodological changes the Commission is Ordering for the Revised 2020 IRP), as well as SCSBA's proposed RP7-A and RP7-B resource plans. DESC shall model price sensitivities for flexible solar PPAs at price points of $38.94/MWh, $36/MWh, and $34/MWh. For the reasons discussed in Section V.D.6, *supra*, that modeling shall include an assumption that the addition of solar PPAs will result in integration costs equivalent to $0.96/MWh. That modeling shall be filed in this docket as well as for informational purposes in the pending generic competitive solicitation proceeding, Docket No. 2019-365-E.

G. Action Plan for IRP Implementation

The evidence in support of this finding of fact is found in the Proposed IRP, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 25

Summary of the Evidence

Several witnesses testified regarding the omission of a short-term action plan from DESC's 2020 IRP, and recommended that such an action plan be included in future IRPs. ORS witness Hayet testified that although it is not statutorily required that a utility include a short-term action plan in its IRP, it is typical that most utility IRPs do include such a plan, (Tr. p. 742.15, ll. 9-13) and in fact, DESC's was one of the only IRPs he was aware of that does not include an action plan, (Tr. p. 745, ll. 18-20). ORS witness Baron testified that "to the extent that there are steps that will be taken . . . in an action plan, the sooner those are identified, the better off all parties, including the company, would be in terms of transparency and how that is evolving." (Tr. p. 781, ll.9-14.) Accordingly, ORS recommended that in future IRPs, the Company should develop a 3-year action plan that identifies all actions the Company intends to take in order to implement its IRP. (Tr. p. 742.9 (Item 27 of Table).) CCL/SACE witness Sommer likewise testified that although an action plan is not specifically required by Act 62, it is important to include an action plan in an IRP for several reasons. An action plan is a helpful summary of the steps that the utility will take to implement its plan; it gives the Commission and intervenors a "heads-up" about when to expect regulatory filings; and it gives a sense of when the utility intends to start and finish an additional analysis to improve the quality of future IRPs, for example, retirement studies. (Tr. pp. 491, l.9 – 492, l.25.)

In rebuttal, Company witness Bell testified that the recommendation that DESC include an action plan in its IRP is "incompatible with the nature of an IRP" and "contrary with the regulatory structure in which it operates in South Carolina." (Tr. p. 65.29, ll. 1-2, & ll. 10-13.)

In response to witness Bell, SCSBA witness Sercy testified that "[a] short-term action plan is an appropriate element to include in an IRP document to clearly identify such actions that are expected to be taken, whether or not those actions require additional regulatory proceedings in order to be fully carried out." (Tr. p. 615.10, ll. 7-10.) In addition, both ORS witness Hayet and CCL/SACE witness Sommer pointed out that Duke Energy's utilities operating in South Carolina include short-term action plans in their IRPs filed with the Commission. (Tr. pp. 479.8 & 748.25.)

Commission Conclusions

In light of the evidence, the Commission finds that inclusion of a short-term action plan is a standard industry practice that would assist the Commission and interested parties in understanding how DESC intends to implement its resource plan. Contrary to the Company's assertions, the Commission concludes that although Act 62 does not require the inclusion of an action plan in a utility's IRP, it is consistent with the regulatory structure in South Carolina for a utility IRP to include a short-term action plan. Accordingly, DESC shall include in its Modified 2020 IRP and in future IRPs a three-year Action Plan identifying and describing the steps it will take to implement its IRP during that three-year period, including but not limited to additional analyses, changes to its methodology, issuance of Requests for Proposals, modifications to its DSM portfolio, and applications for new generating facilities under the Siting Act. The Action Plan shall include a graphic representation of the sequencing of its actions. The Action Plan in the Modified 2020 IRP shall include, at a minimum, the DSM Action Plan discussed elsewhere in this Order; the Company's process for selecting a capacity expansion model, in collaboration with stakeholders; the Company's plans to conduct retirement studies required by this Order; as well as any actions related to competitive procurement of renewable energy resources that may be indicated based on the additional production cost modeling that the Commission is requiring in this Order.

In addition to the Action Plan, Dominion shall explain how the IRP is integrated into other planning at the company by subdivision, division, and department within the Company.

VI. ORDERING PARAGRAPHS

NOW, THEREFORE, IT IS HEREBY ORDERED THAT:

1. Based upon the Proposed 2020 IRP, the testimony, and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission hereby adopts each and every Finding of Fact enumerated herein. The Commission's conclusions of law are fully stated above.

2. Any motions not expressly ruled upon herein are denied.

3. The Commission rejects the Proposed IRP filed by DESC. DESC shall file a Modified 2020 IRP, modified consistent with the directives in this Order within sixty (60) days of the final order in accordance with South Carolina Code Ann. § 58-37-40(C)(3) (Supp. 2019).

4. The Modified 2020 IRP shall be a complete, stand-alone document.

5. The currently scheduled filing dates for Dominion's 2021 IRP Update is held in abeyance and a new filing date for Dominion's next IRP Update shall be set by the Commission following the Commission's final approval of the 2020 IRP.

6. In its Modified 2020 IRP and in its 2021 IRP Update, DESC shall:

   a. Include additional candidate resource plans, representing the near- term deployment of renewables as described in the testimony of SCSBA Witness Sercy (specifically, the resource plans identified as RP7-A and RP7-B).

   b. Re-model the costs of all candidate resource plans, including the additional candidate resource plans required in this Order, with the following changes to the modeling methodology and assumptions:

      i. Use the flexible solar PPA cost assumptions recommended by SCSBA in the Rebuttal Testimony of Witness Sercy, and model 400 MW of

Flexible Solar PPAs starting in 2023 with 20-year PPA prices of \$34/MWh, \$36/MWh, and \$38.94/MWh.

ii. For battery storage PPAs, use the NREL ATB's low storage cost case (including capital and fixed O&M 13 costs) with the same 22% ITC safe harbor assumptions employed for solar PV PPAs.

iii. Correct the incremental flexible solar PPA capacity value assumptions to reflect the ELCC value specific to the existing system penetration level of incremental flexible solar PV.

iv. Assume integration costs of \$0.96 / MWh for solar PV, until an updated, Commission-approved methodology for calculating solar integration costs is available.

v. For ICT, use industry accepted ICT capital cost assumptions, such as NREL.

vi. For its long-term continuing capital cost de-escalation for both solar PV and BESS, correct its implementation of the two different escalation rates consistent with Mr. Stenclik's surrebuttal testimony.

vii. Re-run its production cost modeling using the AEO low, reference, and high gas prices described by SCSBA Witness Sercy in his direct testimony, and using the AEO High CO2 case, also as detailed in Mr. Sercy's direct testimony.

c. Conduct and include in the Modified 2020 IRP an analysis and comparison of all candidate resource plans using the simple quantitative risk metrics recommended by SCSBA Witness Sercy in his direct and rebuttal testimony, including cost ranges and minimax regret scores.

d. Develop and include in the Modified 2020 IRP a set of modifications to the Company's existing DSM portfolio that would achieve at least a 1% level of savings in the years 2022, 2023, and 2024, and screen such measures for cost-effectiveness and achievability.

e. Consistent with step 1 as identified in Hearing Exhibit 16, conduct a "rapid assessment" of the cost-effectiveness and achievability of ramping up its current portfolio to achieve at least a 1% level of savings in the years 2022, 2023, and 2024, and include the results of this rapid assessment in its Modified 2020 IRP. The Company will work with the DSM Advisory Group and, if desired, a contractor selected with input from the Advisory Group, in preparing this assessment.

f. Include in its Modified 2020 IRP action steps the Company will take to complete a comprehensive evaluation of the cost-effectiveness and achievability of DSM portfolios ranging from 1% to 2% savings, as identified in steps 3 through 5 of Hearing Exhibit 16.

7. DESC, in coordination with ORS, shall establish an ongoing IRP Stakeholder Process for the purpose of considering, and inviting stakeholder input and review on, certain potentially complex changes to DESC's IRP development methodology, inputs and assumptions. The IRP Stakeholder Process shall initially consider the following issues:

a. Selection and implementation of capacity expansion modeling software in the IRP development process, considering the criteria set forth in Hearing Exhibit 6,[11] with particular attention to the criteria numbered 1-7 and 9-12;

[11]Hearing Exhibit No. 6 is the Exhibit No. AS-1 presented by the Southern Alliance for Clean Energy and South Carolina Coastal Conservation League Witness Anna Sommer md entered as evidence in the record as Hearing Exhibit No. 6.

b. Implementation of risk metrics and other measures to address ratepayer risk in the IRP development process;

c. Comprehensive retirement analysis of DESC coal plants; and

d. Any other issues, as agreed on by the parties to the Stakeholder process.

e. DESC shall report on the composition and utilization of the Stakeholder process in its 2021 IRP Update. On a semi-annual basis, DESC shall provide a summary update on IRP Stakeholder meetings occurring since the previous report

8. Starting in its 2022 IRP Update, DESC shall implement the following changes to the methodologies used to develop, analyze, and select resource plans:

a. Adopt and implement the use of capacity expansion software, while requiring input from stakeholders and the Commission on the selection and implementation of said software, and ensuring that software meets the transparency requirements of Act 62. DESC shall negotiate a discounted, project-based licensing fee that permits interested intervenors the ability to perform their own modeling runs in the same software package as DESC, and to direct DESC to absorb the cost of these licensing fees. Contemporaneously with the filing of each future IRP, DESC shall make available, without the need for a data request, the modeling inputs (including settings) and outputs, assumptions, any post- processing spreadsheets (e.g. to create the revenue requirements) in electronic spreadsheet format, and the model manual.

b. Develop a wide but plausible range of load forecasts, and ensure that cost modeling captures each resource plan's capabilities to adapt to

load that diverges from the base forecast, as suggested by SCSBA Witness Sercy.

c. Use a wide but plausible range of gas price projections from AEO or another public, credible fundamental gas supply-demand model, as suggested by SCSBA Witness Sercy.

d. Use wide but plausible zero/medium/high CO2 cost projections from AEO or other public sources, as suggested by SCSBA Witness Sercy.

e. Include additional candidate resource plans including DSM and purchased power as resource options that are incorporated into candidate resource plans and evaluated across multiple scenarios

f. Include candidate resource plans to meet the Company's full peaking reserve margin target, and determine in its resource plan analysis what type of resources best meet the peaking increment.

g. DESC should also consider, with stakeholder input, implementation of more sophisticated risk-adjusted metrics appropriate to consider sensitivities including but not limited to natural gas price risk, carbon price risk, and load forecast risk.

h. Specifically consider and discuss diversity of its generation supply, propose candidate resource plans designed to further diversify its generation supply; and include contribution to diversity of generation supply in the evaluation of candidate resource plans.

i. Incorporate the conclusions from the comprehensive coal retirement analysis called for in this Order.

9. DESC shall include in its 2022 IRP a full evaluation of the cost- effectiveness and achievability of four higher levels of capacity and energy savings from DSM: 1.25%, 1.5%, 1.75% and 2%, including the consideration of substantive additions and modifications to the Company's existing DSM portfolio. DESC is directed to work with the DSM Advisory Group in developing this analysis and subsequent portfolio development.

10. In its 2020 Modified IRP, 2021 IRP Update, and subsequent annual Updates prepared pursuant to S.C. Code Ann.§ 58-37-41(D)(1), DESC shall update its planning

assumptions relating to the energy and demand forecast, commodity fuel price inputs, renewable energy forecast, energy efficiency and demand-side management forecasts, and changes to projected retirement dates of existing units. However, other than as required in this Order, DESC shall not make any changes to its modeling or other methodologies, or the sources of data from which it derives its planning assumptions, without disclosing those changes with its update, and describing in concrete and specific terms the impact of those changes on the analysis in the IRP. The Commission may in its discretion permit public comment and/or intervenor testimony regarding any such changes.

11. DESC shall include in its Modified 2020 IRP and in future IRPs a three-year Action Plan identifying and describing the steps it will take to implement its IRP during that three-year period, including but not limited to additional analyses, changes to its methodology, issuance of Requests for Proposals, modifications to its DSM portfolio, and applications for new generating facilities under the Siting Act. The Action Plan in the Modified 2020 IRP shall include, at a minimum, the DSM Action Plan discussed elsewhere in this Order; the Company's process for selecting a capacity expansion model, in collaboration with stakeholders; the Company's plans to conduct retirement studies required by this Order; as well as any actions related to competitive procurement of renewable energy resources that may be indicated based on the additional production cost modeling that the Commission is requiring in this Order.

12. This Order shall remain in full force and effect until further order of the Commission.

BY ORDER OF THE COMMISSION:

Justin T. Williams, Chairman
Public Service Commission of
South Carolina